

+ 303 kilometres
+ 180 days
= choice in supply



SOUTHERN CROSSING PIPELINE. BUILDING VALUE FOR BRITISH COLUMBIA.

BC GAS INC. 2000 ANNUAL REPORT

BC GAS INC. BUSINESS PROFILE

BC Gas Inc. is a leading energy distribution and transmission company as well as a provider of services and supplies related to energy and water distribution. The Company operates primarily in British Columbia and Alberta. Common shares of BC Gas Inc. are traded on The Toronto Stock Exchange under the symbol BCG. The Company's head office is in Vancouver, British Columbia.

Natural Gas Distribution

BC Gas Utility is the largest distributor of natural gas to British Columbians, serving 762,000 customers in more than 100 communities. In November 2000, the Company commissioned the Southern Crossing Pipeline, a 303-kilometre transmission pipeline that provides access to alternative sources of natural gas for B.C. consumers.

Petroleum Transportation

Trans Mountain Pipe Line owns and operates the only pipeline transporting crude oil and refined petroleum products from Alberta to British Columbia and Washington State. With the development of the Corridor Pipeline, scheduled for completion in spring 2003, the Company will participate in the development of the Athabasca oil sands in northeastern Alberta.

Energy and Utility Services

BC Gas Inc. continues to develop its energy and water distribution services and supplies business, primarily through the following businesses:

BCG Services: Water distribution-related supplies and specialty utility services

Measurement Technologies: Management and maintenance of measurement assets for natural gas, water and electric utilities

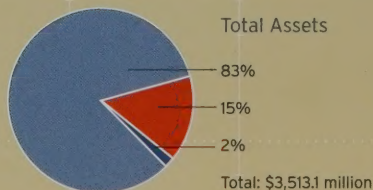
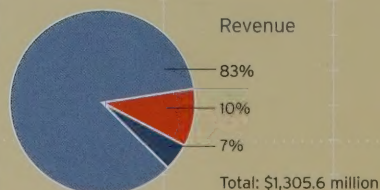
Homeworks: Home comfort and energy-efficiency services and products

BC Gas International: International consulting and engineering, procurement and construction project management

BCG eFuels: Provider of clean transportation fuels

In 2000, BC Gas' core businesses of natural gas distribution and petroleum transportation represented 93% of revenues and 98% of assets.

Year ended December 31, 2000

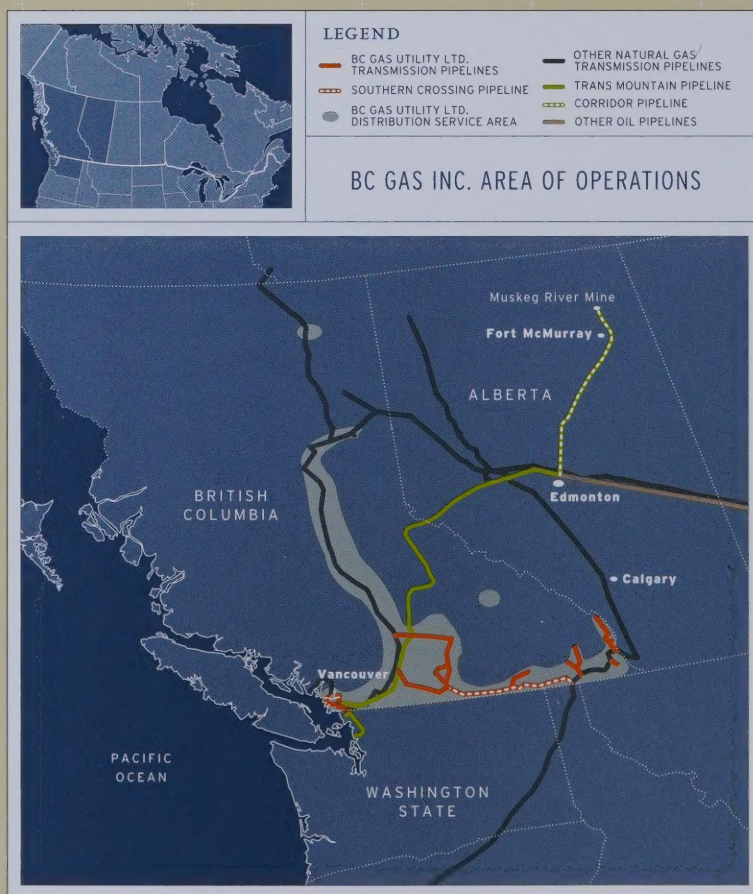


■ Natural Gas Distribution ■ Petroleum Transportation ■ Other Activities

Our strategic plan is based on three corporate goals:

1. We will focus on and expand our core businesses of natural gas distribution and petroleum transportation.
2. We will leverage our expertise and expand our multi-utility business, specifically water and electricity distribution.
3. We will deliver new products to our customers.

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ON THE COVER: Traversing the top of Creston Mountain, the new Southern Crossing Pipeline travels across rugged and forested mountain terrain. This significant technical accomplishment expands our asset base and brings substantial benefits to our customers.

In 2000, BC Gas achieved a number of successes as we implemented our strategic plan. The Southern Crossing Pipeline was brought into service on time and on budget, bringing an alternate supply of natural gas to our customers. We began constructing the Corridor Pipeline, a project that will significantly expand our petroleum transportation business. And all of our business units continued to achieve strong operating performances, contributing to our excellent financial results for the year.

FINANCIAL RESULTS

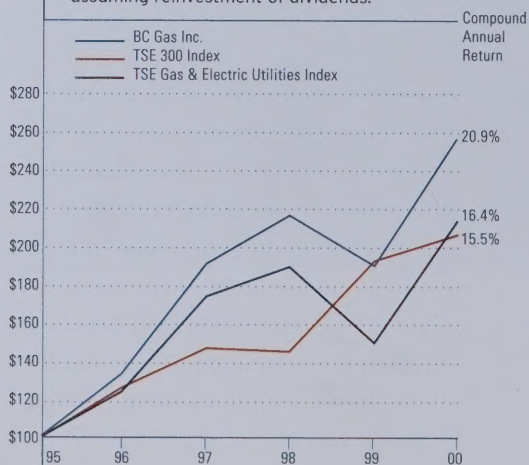
(dollar amounts in millions except per share data)

Years ended December 31	2000	1999	1998
Gross revenues	\$ 1,305.6	\$ 1,040.6	\$ 925.0
Earnings before non-recurring items	\$ 78.8	\$ 74.2	\$ 71.2
Earnings applicable to common shares	\$ 108.8	\$ 81.2	\$ 71.2
Total assets	\$ 3,513.1	\$ 2,480.9	\$ 2,466.1
Earnings per share before non-recurring items	\$ 2.06	\$ 1.94	\$ 1.85
Earnings per share	\$ 2.84	\$ 2.12	\$ 1.85
Dividends per share	\$ 1.225	\$ 1.165	\$ 1.090
Book value per share	\$ 17.86	\$ 16.36	\$ 15.42
Return on common equity	12.0%	12.2%	12.1%

FINANCIAL HIGHLIGHTS

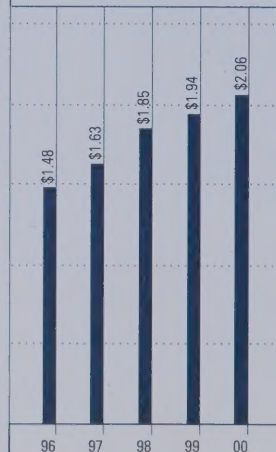
SHAREHOLDER RETURN

Return on an investment of \$100 at December 31, 1995, assuming reinvestment of dividends.



BC Gas continued to outperform both its peer group and the TSE 300 Index for the five years ended December 31, 2000.

EARNINGS PER SHARE BEFORE NON-RECURRING ITEMS



Earnings per share growth was 6.2 per cent in 2000.

NET EARNINGS (LOSS)

(dollar amounts in millions except per share data)

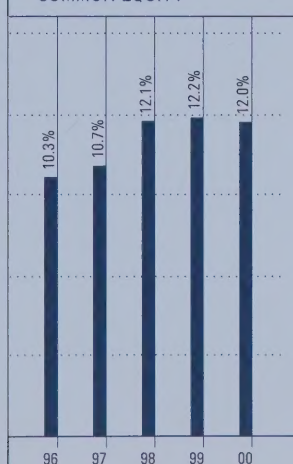
Years ended December 31	2000		1999	
	Per Share		Per Share	
Natural gas distribution	\$ 58.7	\$ 1.53	\$ 51.7	\$ 1.35
Petroleum transportation	21.3	0.56	19.5	0.51
Other activities	(1.2)	(0.03)	3.0	0.08
Earnings before non-recurring items	78.8	2.06	74.2	1.94
Non-recurring items	30.0	0.78	7.0	0.18
Earnings applicable to common shares	\$ 108.8	\$ 2.84	\$ 81.2	\$ 2.12

We achieved our earnings per share growth target of five to six per cent.

We attained our return on equity target of 12 per cent.

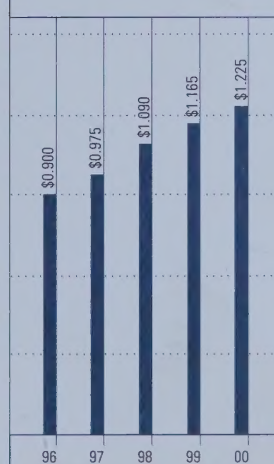
2000 saw the largest capital expansion in BC Gas' history, with capital expenditures of \$621 million.

RETURN ON
COMMON EQUITY



In 2000, BC Gas again achieved its targeted return on equity of 12 per cent.

DIVIDENDS PER SHARE



Dividends to shareholders in 2000 were \$1.225 per share, up 36 per cent from 1996.



Ronald L. Cliff, Chairman (right)
John M. Reid, President and Chief Executive Officer

LETTER TO SHAREHOLDERS

The year 2000 was a tumultuous one for the North American energy industry. Substantial and sustained supply and demand imbalances, particularly in the western portion of the continent, resulted in dramatic price escalation in the markets for electric power and natural gas.

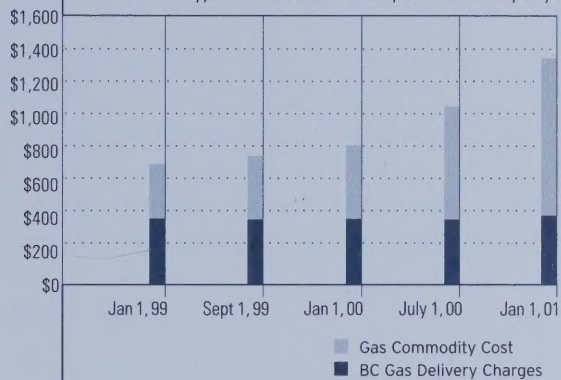
strategic focus

+ managed risk

+ solid growth

= shareholder value

BC GAS UTILITY LTD.
TYPICAL ANNUAL RESIDENTIAL BILL 1998 – 2001
Based on a typical residential consumption of 110 GJ per year



Dramatic increases in customer gas bills have been due primarily to rising gas commodity costs across North America.

This was particularly true for BC Gas Utility residential customers who, following a seven per cent increase in rates in January 2000, saw an unprecedented 33 per cent increase in July and a further 27 per cent effective January 2001. Customers who for many years had given little thought to their natural gas bills sought answers about every aspect of the value chain from exploration to export. As the largest gas distributor in British Columbia, we took the lead in the public dialogue which culminated in the province providing relief by way of energy rebates to residential and institutional customers.

There is no question that the turmoil has caused some strained relations with customers who simply did not understand our role in the provision of energy to their homes and businesses. However, we believe we are making progress in educating the public that our shareholders do not profit from higher natural gas prices. We are also heightening public understanding of the relationships between electricity and natural gas in the total energy equation.

Sometimes lost in the clamour over gas prices is the fact that 2000 was a year when significant elements of our strategic plan were implemented. The Southern Crossing Pipeline was constructed and put into service. It was designed to meet peak day demands of our core market customers by delivering gas into our Interior service area from the TransCanada system and freeing Westcoast Energy capacity to flow to the Lower Mainland. After suffering the winter's supply constraints at the Sumas hub on non-peak days, we are considering extending the pipeline to provide baseload gas from the Alberta hub to the Lower Mainland.

The new customer information system, rolled out to serve Interior customers last spring, has delivered results beyond expectations and has been key to our Kelowna, B.C. call centre being responsive to the sharply increased demands of customers as their gas bills went into uncharted territory. This technology will be extended to our Lower Mainland customers by the end of 2001.

Construction was completed and employees began moving into our new Operations Centre in Surrey, B.C. in October. This modern facility, which we are pleased to note won an energy efficiency award from the Government of Canada, brings together gas utility employees from a number of centres and is designed to promote a collaborative work culture. We began implementation of our automated mobile dispatching and work management system to improve productivity of our field personnel and will complete the project during 2001. These initiatives represent significant capital investments that will enable us to be more responsive to customer needs at competitive costs as we progress toward an unbundled retail gas environment.

In petroleum transportation, construction began on the Corridor Pipeline, the 493-kilometre parallel pipeline system that marks our entry into the Athabasca oil sands transportation business. This region contains the world's largest deposit of heavy oil and a significant part of Canada's energy future. We are well positioned to play a key role in its growth and development. We have begun the process of relocating Trans Mountain's head office to Calgary, Alberta — closer to shippers and to the Canadian oil and gas industry.

We remain committed to our corporate strategy to focus on our base businesses of natural gas distribution and petroleum transportation. We are also committed to building on the competencies that make us successful in these base businesses to develop related businesses such as water transportation and services.

Sticking to our business continues to yield positive financial results, with earnings per share before non-recurring items up from \$1.94 in 1999 to \$2.06 in 2000. We have also maintained our superior share performance relative to our utility peer group and the TSE 300 Index.

On the regulatory front, a new multi-year regulatory agreement was negotiated for our petroleum transportation company, Trans Mountain Pipe Line, and we are working to achieve a similar multi-year agreement for BC Gas Utility in 2001. These agreements provide operating incentives that allow for incremental shareholder returns and ongoing benefits for our customers. Our relationships with our regulators remain constructive and we are working with them closely, particularly with respect to the natural gas utility as deregulation in that industry progresses.

We had hoped to establish a partnership between BC Gas and BC Hydro, the provincial electric utility, to provide joint billing and customer contact management services. This arrangement would have allowed us to realize some long-term operating efficiencies, and preserved the single gas/electric bill for the majority of our customers. Unfortunately, the differences in the electric and natural gas deregulation schedules and the respective needs and resources of the two

organizations have created very disparate requirements for customer relationship management to the extent that we were unable to proceed with the arrangement. Though disappointed, we are seeking similar opportunities that will allow us to realize the strategic benefits a joint arrangement would provide.

EXCELLENT PROMISE FOR MULTI-UTILITY

We remain excited by the potential of securing a lead position in the provision of multi-utility services and supplies in our market area. Our water business acquisitions have added to our capabilities and we are actively pursuing opportunities that would allow us to move into water utility operation. We were chosen by the City of Kelowna, B.C. to provide integrated measurement, billing and customer contact management for water, electricity and natural gas. This project represents an excellent example of how customers and utilities can realize the many benefits of the multi-utility model and we hope to replicate this arrangement elsewhere.

Strong progress is being made in the development of our natural gas vehicle fuel business. In addition to opening several new refuelling stations in Vancouver, B.C., Toronto, Ontario and Phoenix, Arizona and forming a marketing partnership with Ford Motor Company, we announced a strategic alliance with Westport Innovations Inc., a leading developer of high performance natural gas fuel systems for diesel engines. All of these efforts will place us in the forefront of a rapidly growing marketplace for cleaner vehicle fuels.

WITH THANKS,

Robert E. Kadlec and Thomas A. Buell have indicated they will not be standing for re-election to the Board of Directors at the Annual General Meeting of the Company in April 2001. Both individuals have made many outstanding contributions to the Company over a period of many years. Bob Kadlec served as President of the Company from 1972 to 1995. His vision and commitment were fundamental to the dramatic growth that the Company achieved under his leadership. Tom Buell has been a member of the Board of BC Gas and its predecessor company, Inland Natural Gas, since 1984. During his 16 years on the Board, he has consistently provided sound advice and counsel which has contributed greatly to the success of the Company.

We wish both of these outstanding business leaders well in their retirement.

FUTURE CONSIDERATIONS

Though we expect natural gas commodity prices to remain volatile for some time, we have fundamental confidence in the role natural gas plays as part of the long-term energy solution. Clearly, the demand for British Columbian natural gas will continue to be substantial due to sustained increases in the demand for natural gas-generated electric power.

Given this future, we are encouraging government representatives to recognize the need for integrated energy policy and regulation that maintains the province's inherent energy advantages and gives us access to other sources of supplies. The pipeline capacity bottlenecks and the fears of energy scarcity in an area rich with resources must be eliminated. It must be recognized that our capital and energy markets are continental and reasonable rates of return must be available to attract investment for the development of additional natural gas infrastructure. Regulatory and bureaucratic impediments must be reduced or eliminated to reduce the lag in response time to construct needed infrastructure.

And while the issues at hand are critical, BC Gas is well-positioned to maximize on opportunities in infrastructure development that will benefit our customers and our shareholders in the long-run.

ACKNOWLEDGING OUR EMPLOYEES

We recognize and appreciate our employees for their ongoing commitment and dedication during a year in which they have been significantly challenged. Gas price increases have made employees the target of dissatisfied customers, we have introduced a number of new initiatives that have changed the way we operate and we have asked many of our employees to move their work location. On behalf of our shareholders, we thank all our employees for their admirable and sustained contribution to the organization.

BC Gas remains committed to offering its shareholders a low-risk investment with attractive returns that is focused on our core competencies in energy and utility services. We are pursuing solid growth opportunities while at the same time carefully managing our level of risk, with the result that we continue to offer our shareholders a solid, stable investment in a growing sector.



Ronald L. Cliff
Chairman



John M. Reid
President & Chief Executive Officer

February 15, 2001



The Southern Crossing Pipeline includes one modified and two new compressor stations. Southern Crossing's capacity can be increased cost-effectively by adding additional compression.

NATURAL GAS DISTRIBUTION

BC Gas is the leading provider of natural gas service in British Columbia. In 2000, we realized several important achievements, with the most notable being the completion of the Southern Crossing Pipeline. This project adds considerably to our asset base and was built to meet peak-day demand as well as provide our customers with access to new sources of natural gas. Investments in our technology infrastructure and the restructuring of BC Gas Utility's operations along business lines were other important initiatives in 2000 that contributed to our goal of optimizing the efficiency and effectiveness of our utility business.

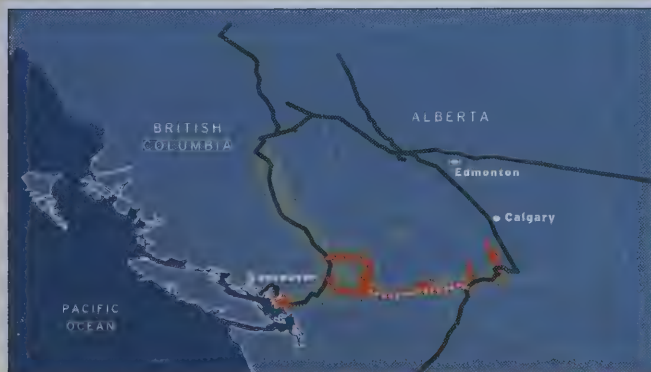
SOUTHERN CROSSING PIPELINE

The Southern Crossing Pipeline was one of the most complex and difficult pipeline projects ever undertaken in Canada. This transmission pipeline — which extends 303 kilometres in southern B.C. from Yahk to Oliver and includes two new compressor stations — crossed significant mountain terrain, agricultural and private residential land, dense forest, numerous rivers and other sensitive environments and was often required to be constructed in constrained areas and with difficult access for manpower and equipment.

Our team met the many challenges of this project and accomplished a significant engineering and construction feat by completing the pipeline in six months, on time and on budget.

The Southern Crossing Pipeline was the first major linear project developed under the province's strict new environmental assessment regulations. In addition to meeting all environmental commitments, the project brought economic benefits to the province and to local communities, and it successfully addressed the diverse requirements of landowners, provincial government agencies, First Nations and municipalities.

We are particularly pleased with the extent to which we were able to work on the project with First Nations in the province. Not only did they participate in initial route selection and environmental services, but they were also actively involved in logging and construction and will be involved in final restoration. The relations we built during the project will serve us and First Nations for the future.



NATURAL GAS DISTRIBUTION

LEGEND

- BC GAS UTILITY LTD. TRANSMISSION PIPELINES
- - - SOUTHERN CROSSING PIPELINE
- BC GAS UTILITY LTD. DISTRIBUTION SERVICE AREA
- OTHER NATURAL GAS TRANSMISSION PIPELINES

With natural gas now flowing through its 24-inch diameter pipe, the Southern Crossing Pipeline allows us to access natural gas from sources other than northern B.C. and reduces our dependence on Westcoast Energy as our primary transmission service provider.

THE RISING PRICE OF NATURAL GAS

The price of natural gas has increased significantly over the last year because of increased exports of natural gas from Western Canada to the western United States, particularly California, where demand for natural gas to fuel electricity generating stations is surging. Furthermore, consumers of natural gas in B.C. have been forced to pay for natural gas at rates in excess of other Canadians because of limited pipeline capacity. Additional pipeline capacity in the province would allow consumers to source natural gas elsewhere and avoid paying rates that at times this past winter were almost double those elsewhere, including neighbouring Alberta.

Pressures on natural gas prices are expected to escalate further over the next five years as generating stations in western North America switch to natural gas and as export capacity increases following the November 2000 start-up of the third-party Alliance Pipeline from northern British Columbia to Chicago. Primarily as a result of higher commodity prices charged to us by natural gas producers, BC Gas implemented rate increases from December 1999 through January 2001 totaling 79 per cent.

Natural gas is a primary source of home heating in British Columbia and, because of higher commodity prices, the average homeowner will pay approximately twice as much to heat a home for the winter of 2000 compared to two years ago. The escalating price of natural gas presents a challenge for many customers in our service area. Over the past year, we have undertaken numerous initiatives to help our customers cope with a difficult situation. We are encouraged by recent financial assistance from both the federal and B.C. governments, targeted at the residential marketplace.

In the summer of 2000, BC Gas Utility stored approximately 25 per cent of its winter gas requirements. At the same time, we contracted for 25 per cent of our supply to be delivered in northern B.C. and Alberta at the prices that are in effect there — as opposed to the elevated prices experienced in the rest of B.C. Finally, we used financial instruments to lock in prices for 10 per cent of our

winter gas, ensuring a more favourable price than we would have had on the open market. Together, these actions have shielded our customers from about \$500 million in costs this year.

The development of further new pipeline capacity, particularly to the province's heavily-populated Lower Mainland area, is still needed, however, to meet demand and alleviate pricing pressures. By providing access to natural gas produced in Alberta, an expansion of the Southern Crossing Pipeline offers the opportunity to do this.

An intensive media campaign was launched in the fall of 2000 to help consumers manage energy costs through conservation and efficiency measures. We are also sponsoring a school-based program — called Destination Conservation — which trains teachers, custodial staff and students on how to reduce energy and water consumption. In 2001, BC Gas is helping to sponsor 61 schools in four different school districts.

NEGOTIATING AN INCENTIVE-BASED AGREEMENT

BC Gas worked closely with customers and the British Columbia Utilities Commission to extend its incentive-based agreement to December 31, 2001. We are initiating plans to negotiate and implement a new multi-year settlement that would take effect on January 1, 2002. Under these incentive-based agreements, customers and shareholders share the benefits of operating efficiencies and initiatives to minimize the cost of natural gas service.

STRENGTHENING OUR CORE BUSINESS

We actively maintain and improve our natural gas system to meet ongoing growth demands and to ensure facilities are operated in a safe and environmentally responsive manner. In 2000, we made a number of system improvements, including the installation of two compressor stations associated with the Southern Crossing Pipeline and modification of a third station. An additional compressor station was constructed to meet growing demands for natural gas in the Greater Vancouver area. And in Quesnel, B.C., steel piping was replaced with flexible PVC plastic piping to help the system withstand ground movement.

As part of BC Gas Utility's commitment to delivering superior customer service, we introduced a new customer information and billing system for about 250,000 of

our customers. The new system — which will be expanded to include all customers — enables customers to directly access information about their account via telephone or the Internet and provides better information and support for our customer service representatives. The system also allows BC Gas to enhance its customer billing capabilities in advance of further deregulation and competition.

We are also enhancing customer service by investing in our technology platform. Two projects were rolled out in 2000 and will be completed in 2001. Digital mapping and facilities management databases are now in use and are assisting us in managing our underground distribution system, resulting in faster emergency response and a superior process for the design of new service applications. Second, our new mobile data dispatch technology is in use in several areas and will improve field operations management and allow us to centralize all dispatch centres in our Surrey, B.C. operating centre. This will create productivity and efficiency improvements by helping us better coordinate our work and will improve scheduling of customer appointments. In 2001, we will implement a preventative maintenance risk analysis program to improve our efficiency and effectiveness in maintaining the natural gas system.

We are exploring the potential of e-commerce by developing a customer-focused Web site that enables BC Gas customers to access product and service offerings and request services on-line. These enhancements will expand the ways in which we communicate with and provide services to our customers.

During 2000, BC Gas Utility operations were restructured along customer business lines to provide a more effective structure for delivering continued improvements in service quality. These changes build on other customer-oriented organizational changes implemented in 1999.

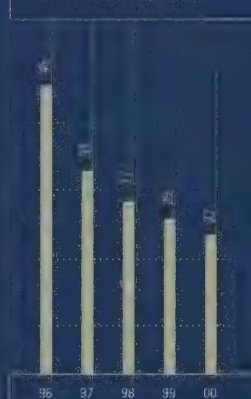
To help BC Gas Utility employees continue to thrive in an increasingly competitive environment, we are working to improve internal communication and employees' understanding of our strategic direction and how their job roles are linked to company success. The opening of the Utility's new operations centre in Surrey is expected to foster increased sharing of employee knowledge and expertise by having the majority of employees based in one central location. The operations centre was officially opened in December 2000.

CONTINUING TO FOCUS ON SAFETY

BC Gas Utility is committed to employee and public safety and is striving for continuous improvement. In 2000, the Company began benchmarking its safety performance against the multi-year averages of the Canadian Gas Association. As a result of a greater focus on the importance of safety, the number of lost-time injuries at BC Gas decreased 12 per cent from the previous year and is now nearing the Canadian Gas Association's multi-year average. In addition, BC Gas' preventable vehicle accidents were down 25 per cent from 1999.

BC Gas is dedicated to increasing public and customer safety by providing information through various channels — including bill inserts and advertising — on the safe use of natural gas. This information focuses on encouraging people to call before they dig (to ensure they are aware of the location of gas lines), to have people take immediate action if they smell natural gas and to encourage customers to have their appliances serviced regularly. In 2000, BC Gas, the provincial government and other natural gas utilities developed brochures on natural gas and carbon monoxide safety that were distributed to all fire departments in the province.

LOST-TIME INJURIES



Our focus on improving employee safety performance has had demonstrable results, with lost-time injuries decreasing for each of the past five years.



The construction project to build the Corridor Pipeline began in August 2000 and work is proceeding on schedule and on budget.

PETROLEUM TRANSPORTATION

Over the past year, several accomplishments helped to strengthen and expand our petroleum transportation business. Trans Mountain negotiated with its shippers a new five-year incentive toll settlement that will create a more stable pricing environment for shippers on its mainline pipeline system and represents an important step as the industry moves towards deregulation. Restructuring over the past year has led to increased efficiencies and cost savings. Finally, Trans Mountain began constructing the Corridor Pipeline, a \$688-million project that will add considerable value to our asset base and enable us to participate in the development of the Athabasca oil sands in northeastern Alberta.

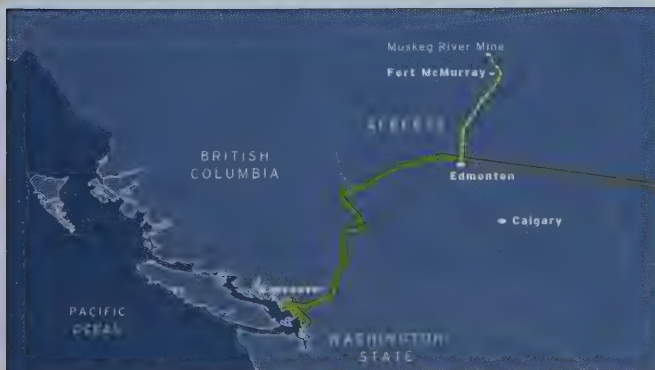
CORRIDOR PIPELINE

In August 2000, Trans Mountain Pipe Line Company began constructing the Corridor Pipeline. The pipeline is part of the Athabasca Oils Sands Project, under development by Shell Canada Limited along with Western Oil Sands Inc. and Chevron Canada Resources Limited. When completed, the 493-kilometre Corridor Pipeline will be the world's longest dedicated diluent/bitumen pipeline. It will connect the new Muskeg River Mine, located just north of Fort McMurray and set to open at the end of 2002, with an upgrader to be constructed adjacent to Shell's Scotford refinery north of Edmonton. Corridor will be capable of shipping 215,000 barrels per day of diluted bitumen, including 150,000 barrels

of bitumen and 65,000 barrels of diluent. Designed, constructed and operated by Trans Mountain, the pipeline will be owned by a BC Gas subsidiary.

During the past summer, the contractor successfully installed 72 kilometres of dual pipelines near the Edmonton end of the Corridor system and in December activity commenced on the 140-kilometre winter 2001 construction spread. The project is proceeding on schedule and within budget. Linefill and start-up are scheduled to begin at the end of April 2002, with completion of the project slated for spring 2003.

By building the pipeline over a three-year period, we are benefiting from significant cost savings and are reducing



PETROLEUM TRANSPORTATION

LEGEND

- TRANS MOUNTAIN PIPELINE
- - - CORRIDOR PIPELINE
- OTHER OIL PIPELINES

the risk of cost overruns. The construction for this project is estimated to cost \$688 million. Because of the strong support provided by BC Gas to the Corridor Pipeline project, Corridor was able to establish a commercial paper program to finance its borrowings, a first in Canada for pipeline project financing. This will deliver significant cost reductions to the shippers on the Corridor Pipeline system.

The Corridor Pipeline adds to our asset base and will significantly expand our petroleum transportation business. It will enable us to participate in the development of the Alberta oil sands, an area the Canadian Association of Petroleum Producers estimates will be responsible for 40 per cent of oil production in Western Canada by 2003. This project also offers attractive returns with a low risk profile and takes advantage of Trans Mountain's recognized expertise in operating oil pipelines.

DELIVERY VOLUMES

In 2000, petroleum transportation contributed 56 cents to the Company's earnings per share. The five cent improvement over 1999 reflects higher U.S. delivery volumes and improved operating performance in the year. Deliveries of crude oil and refined products on Trans Mountain's mainline system from Edmonton, Alberta to British Columbia and Washington State were 32,533 cubic metres per day, compared with 32,988 in 1999. Deliveries were substantially higher during the second half of the year, due to higher demand in Washington State and increased shipments to other export markets, including California, reflecting improved profit margins for refined products.

INCENTIVE TOLL SETTLEMENT

During 2000, Trans Mountain negotiated a second five-year incentive toll settlement for its Canadian mainline system.

The settlement — covering 2001 through 2005 — builds on the mutually beneficial partnership between Trans Mountain and its shippers and represents a significant step forward in the evolution of economic deregulation. The settlement is subject to approval by the National Energy Board (NEB), following negotiations between the Company and shippers over the past year. It provides shippers and producers with toll stability and certainty, as tolls calculated for 2001 will remain in effect for the five-year settlement period. It also provides for future adjustments to reflect volume variances outside the defined range and other defined adjustments. It is expected that the NEB will approve the arrangements during the first half of 2001.

This new settlement will create a more stable pricing arrangement for shippers than the previous agreement, where shippers and Trans Mountain shared in net earnings above a specified threshold level. The total share of pre-tax revenues from 2000 incentives that will be credited in 2001 to mainline shippers is \$5.2 million, compared with \$2.5 million for 1999. The higher amount reflects increased earnings in 2000.

The new settlement also provides opportunities for Trans Mountain, giving the Company greater responsibility to manage the costs of pipeline operations and retain the full benefit of any realized efficiencies and savings. Under the new settlement, Trans Mountain assumes risks and rewards of throughput variance within a defined range of throughput volume.

Trans Mountain will also benefit from cost efficiencies associated with a major restructuring of the Company over the past year. As part of the restructuring, Trans Mountain is making greater use of technology throughout its system, consolidating certain functions at its control centre and relocating the control centre to Edmonton. These changes



When completed, the Corridor Pipeline will be the longest dedicated diluent/bitumen pipeline in the world, stretching 493 kilometres from the Muskeg River Mine north of Fort McMurray to Edmonton, Alberta.

will enable Trans Mountain to achieve further efficiencies once the Corridor Pipeline is operational.

In conjunction with the restructuring, Trans Mountain's head office is being relocated to Calgary to be closer to customers and to position the Company to take advantage of growth opportunities in Western Canada. In addition to the Corridor Pipeline project, Trans Mountain is working on potential opportunities in petroleum transportation and terminalling related to further development of the oil sands in Northern Alberta.

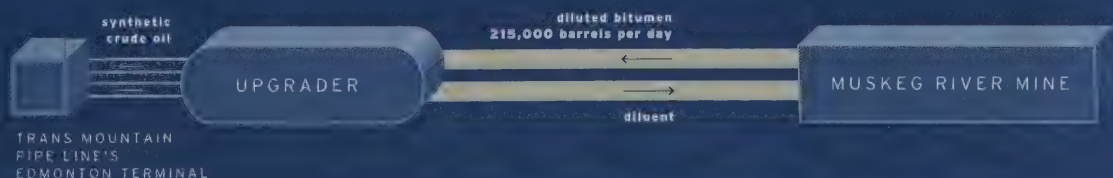
Trans Mountain remains committed to safe operations and environmental stewardship and has a number of programs in place to ensure environmental protection, superior safety performance and pipeline integrity. Trans Mountain's Environmental Management System (EMS) is designed to ensure that it complies with applicable regulatory requirements and manages environmental risks. The EMS is reviewed regularly and was most recently updated in early 2000. Environmental protection governs all operations from the planning and management of environmental issues to identifying potential problems and taking preventive action in the field.

At the core of Trans Mountain's spill prevention efforts is its extensive pipeline integrity management program. It includes corrosion control measures, in-line inspections, anomaly investigations, pipeline repairs and replacement, hydrostatic testing, and monitoring of third-party activity.

During the year, Trans Mountain experienced one reportable oil spill on Company property in Washington State. The spill occurred during a refilling operation following routine maintenance and did not result in any adverse environmental or public health impacts. The incident has been thoroughly reviewed, and corrective measures were implemented.

FACTS ABOUT PETROLEUM TRANSPORTATION

- 1 Trans Mountain Pipe Line owns and operates the only pipeline transporting crude oil and refined petroleum products from Alberta to British Columbia and Washington State.
- 2 With the development of Corridor Pipeline, the Company will participate in the development of the Athabasca oil sands, the world's largest deposit of heavy oil and bitumen.
- 3 The Canadian Association of Petroleum Producers estimates that by 2003 oil sands mining and in-situ bitumen production will account for more than 40 per cent of Western Canadian oil production.
- 4 The Corridor Pipeline adds to our asset base and will significantly expand our petroleum transportation business.
- 5 By building the pipeline over a three-year period, we are benefiting from significant cost savings and are reducing the risk of cost overruns. The construction for this project is expected to cost \$688 million.
- 6 Corridor Pipeline offers attractive returns with a low-risk profile and takes advantage of Trans Mountain's recognized expertise in operating oil pipelines.
- 7 When completed in spring 2003, Corridor will be the longest dedicated diluent/bitumen pipeline in the world.





Our water business positions us to deliver integrated multi-utility services for municipalities, developers and other customers.

ENERGY AND UTILITY SERVICES

At BC Gas, we're building on our core strengths and taking a measured approach in developing businesses that complement and strengthen our proven areas of expertise. These businesses are future-oriented and currently represent a small portion of the Company's activity.

BCG SERVICES

A wholly owned subsidiary of BC Gas, BCG Services provides waterworks and other water-related supplies and specialty utility services for municipalities, institutions, resorts and industrial customers. With the consolidation of four water businesses acquired in 1999 and 2000, BCG Services is actively participating in the developing water industry in Alberta and British Columbia. BCG Services supplies infrastructure materials — ranging from pipes and valves to fire hydrants, pumps and irrigation equipment — to their broad base of customers. BC Gas' investments in water supplies and services strengthen existing relationships with key customer groups and position BCG Services to take advantage of new opportunities in the water business, which is expected to grow as municipalities seek to manage consumption of this valuable resource. BCG Services was selected by the City of Surrey to provide a water meter program including marketing, supply and installation services. In addition, the Company was chosen by the City of Kelowna to provide integrated measurement, billing and customer contact management for water, electricity and natural gas customers in the city. The Company plans to use these projects as models for multi-utility expansion elsewhere. BCG Services is also expanding its market position in pumping and in-place pipe rehabilitation and restoration; recently, it rebuilt a water pump for one of the major water distributors in the City of Kelowna.

The planned acquisition of additional water supply and service operations over the coming year, and the expansion and introduction of new products and services to all branches, will help BCG Services grow its presence in the Pacific

Northwest. Revenues from the Company's water business were in excess of \$70 million in 2000.

BCG Services also provides energy services to customers located outside the utility's service area. With the addition of IntraWest's Panorama Resort near Invermere, B.C. in 2000, BCG Services now provides energy and utility services to three ski resorts in British Columbia. BCG Services also markets technology products and services related to utility operations, including a Web-based emergency management system for utilities, municipalities and industrial customers.

MEASUREMENT TECHNOLOGIES

BC Gas is capitalizing on its expertise in measurement technology to take advantage of opportunities to manage and maintain measurement assets for natural gas, water and electric utilities across North America. Measurement Technologies, a business unit of BC Gas, is a partner with Invensys plc in the joint venture Measurement Solutions International (MSI). In 2000, MSI signed a Memorandum of Understanding to offer a full range of metering and measurement services to utilities and energy services providers in the northeastern United States. These services will be delivered by a new joint venture company between MSI and South Jersey Industries.

In Canada, Measurement Technologies is currently accredited nationally by Measurement Canada and certified under ISO 9002. It is therefore well positioned to provide meter inspection services for gas and electric utilities as Measurement Canada withdraws its services in favour of independent meter inspection suppliers.



Through BCG eFuels, we provide clean transportation fuels for a variety of commercial fleets. In 2001 we will expand our network of refuelling sites in Vancouver, Toronto and Phoenix.

HOMEWORKS

The Company's residential services subsidiary, Homeworks, continued to compete in the home services market with a high level of customer satisfaction. It has become one of the largest energy retrofit companies in B.C., specializing in services designed to improve home comfort and energy efficiency. Improving energy efficiency is an important consideration for homeowners, given recent increases in natural gas commodity prices.

Building on its Homeworks Financing Program, the "Loan by Phone" program was introduced allowing the Homeworks dealer network to process loan applications through a call centre and Internet application.

Homeworks has also begun to work with another BC Gas Inc. subsidiary, BCG Services, in creating Homeworks Water Solutions. This program focuses on the installation and repair of septic tanks and septic systems, incorporating Homeworks financing as appropriate. The Homeworks Heating Program, offered through our alliance with Lennox Inc., continued to develop its consumer presence in the provision of repair, maintenance and installation of heating-related products such as furnaces, fireplaces and hot water tanks.

BC GAS INTERNATIONAL

BC Gas International provides consulting and engineering services to clients around the world. In the United Arab Emirates, BC Gas International is working in conjunction with its local partner, the S.S. Lootah Group, on the second phase of the first natural gas distribution system in the country. Scheduled for completion in March 2002, the \$40 million second phase will extend the natural gas system in the City of Sharjah following the successful completion of the first phase in 2000. The City of Sharjah plans to develop two additional phases.

As part of its contract in Sharjah, BC Gas International has developed a project management and quality program that is ISO 9001 certifiable and available for use by other BC Gas companies. BC Gas International is also forming alliances with other major energy companies to take advantage of emerging opportunities in the Middle East where a number of large natural gas projects are planned for development.

BC Gas International provides consulting and training services for utilities and municipalities in regions where there is strong demand for expanding and rehabilitating natural gas distribution infrastructure. In Russia, BC Gas International is developing an environmental management system framework for the oil and gas industry — a three-year project that is funded by the Canadian International Development Agency. BC Gas International is also pursuing other projects in the engineering, procurement and construction sector and is investigating opportunities to provide bundled multi-utility services.

BCG eFUELS INC.

Clean vehicle fuels such as natural gas create less smog and particulate and have less impact on climate change than gasoline or diesel. Two years ago, we created BCG eFuels Inc., a new company that is quickly emerging as a leading provider of clean transportation fuels. This year BCG eFuels negotiated a three-year agreement with the Ford Motor Company to support its marketing of factory-built natural gas powered vehicles (NGVs) for use by commercial fleets in Vancouver, Toronto and Phoenix. The arrangement with Ford builds on our NGV expertise in working with commercial fleet customers — police, taxis, buses and courier and delivery companies — and will also bring expanded fuelling infrastructure to those cities.

BCG eFuels is now the largest provider of compressed natural gas fuel for NGVs in British Columbia, with 37 refuelling sites. Over the next year, we plan to add five or more new sites in British Columbia, five in Toronto, and up to eight in Arizona. BCG eFuels is also looking into other US markets such as California, Nevada, Oregon and Washington. To broaden our product base and scope of operations, BC Gas recently sold a minority interest in BCG eFuels to Westport Innovations Inc. Westport is a leading developer of high-pressure direct injection natural gas fuel systems for diesel engines. This development will involve BCG eFuels more directly in the heavy truck market, which will in future consume increased volumes of liquefied natural gas fuel.



BC Gas' four municipal relations managers work closely with municipalities throughout British Columbia.
Left to right: Allan Chabot (Prince George), Rob Greno (Penticton), Ron Baker (Vernon) and Don Rankin (Vancouver).

WORKING WITH OUR COMMUNITIES

At BC Gas we are proud to support and strengthen the communities in which we operate. BC Gas Utility serves 762,000 customers in more than 100 communities. Trans Mountain's pipeline passes through approximately 40 communities in Alberta, British Columbia and Washington State.

COMMUNITY INVOLVEMENT

In 2000, we appointed four account managers to serve as single points of contact for municipalities in their regions. In addition to making it easier for our municipal customers to do business with us, this approach strengthens our presence in local communities and helps us better understand their needs and concerns.

BC Gas supports the well-being of communities where it operates through a wide variety of initiatives and partnerships. To achieve the greatest benefit, we work with local organizations on long-term programs that help people help themselves or that recognize groups or individuals who make a difference. Last year, for example, BC Gas Utility continued as a major sponsor of the West Coast Disaster Response Conference with the Neighbourhood Spirit Awards, an initiative that during the past year recognized emergency preparedness volunteers from 16 communities in our service area. All volunteers were nominated by local mayors for their outstanding contributions to emergency preparedness and response capability in their community.

The United Way Employee Giving Campaign is an integral part of the corporate culture of BC Gas. In fact, BC Gas employees continue to be among the highest per capita contributors to United Way throughout British Columbia. In 2000, our president John Reid chaired the United Way Campaign for the BC Lower Mainland.

As part of our commitment to education, Trans Mountain offers scholarships in the fields of science and technology to 60 high schools and post-secondary institutions in Alberta, British Columbia and Washington State each year. Trans Mountain is also a proud supporter of the arts, contributing to a variety of cultural groups and community events. For more than a

decade, Trans Mountain and the City of Burnaby, B.C. have co-sponsored the Vancouver Symphony Orchestra's popular annual summer concert in Deer Lake Park.

ENVIRONMENT

We are committed to continuously improving our health, safety and environmental performance throughout our operations. In 2000, BC Gas Inc. adopted a comprehensive policy governing all member companies. This policy gives us a structure for managing our business with respect to health, safety and environmental issues and enables us to set clear operating targets and objectives. The new policy was audited in 2000 by an external third party. The resulting evaluation acknowledged that the BC Gas Health, Safety and Environment Policy and supporting environmental management system is now compliant with the international ISO 14001 environmental standard. In January 2001, BC Gas launched its second five-year schedule of environmental audits and initiated a corresponding five-year safety audit plan. The BC Gas environment and safety audit program is an integral component of our management system, providing a tool to assess compliance with regulations and corporate policy as well as a review of good management practices.

In 2000, Trans Mountain contributed to a three-year project being conducted by the University of Alberta and Parks Canada to develop techniques for rehabilitating disturbed areas in the mountainous region of Jasper National Park. This project will provide us with proven methods of re-establishing vegetation on rights-of-way after completing maintenance work.

GREENHOUSE GAS EMISSIONS

During the year, BC Gas Utility conducted a detailed internal review to measure actual greenhouse gas emissions from its natural gas distribution system. By providing a true measure of emissions, the review has enabled the Company to establish an increasingly accurate base of information for future measures and emissions management forecasts. In the past, our greenhouse gas emission estimates were based to a large degree on industry emissions models. As a result of the internal review — which involved attaching measurement tools to compressors, lines and other system equipment — our greenhouse gas emission profile has been substantially reduced, reflecting the relative newness and efficiency of our system when compared with many others in the industry.

BC Gas Utility is recognized as one of the lowest greenhouse gas emitting distribution companies of its size in Canada. Our efforts to identify, measure and minimize greenhouse gas emissions are an integral part of our operations and include the purchase of appropriate equipment and materials, modification of operating procedures and efficient energy utilization in our facilities.

In 2000, BC Gas was awarded gold level reporting status from Canada's Climate Change Voluntary Challenge and Registry, a program designed to encourage and track voluntary reductions of greenhouse gas emissions. Gold level reporting status recognizes quality reporting with specific measures and targets.

Trans Mountain continues its support of Tree Canada Foundation's locally sponsored tree-planting programs. In addition to making the communities more green, these programs help companies offset carbon dioxide emissions. Last year was the third year of Trans Mountain's contribution to Tree Canada, and planting programs were carried out in the Fraser Valley, Abbotsford, Blue River, Chilliwack, Hope and Langley in British Columbia and in Hinton, Alberta.

FIRST NATIONS PROGRAM

Our stakeholders comprise a broad range of people in communities across our service area and include many First Nations groups. Our utility pipelines cross the land of 11 First Nations bands. We are dedicated to strengthening our relationships with First Nations communities and we are working at the grassroots level to achieve this goal and to develop business opportunities.

In addition to our work with First Nations on the Southern Crossing Pipeline, in 2000 we worked on several initiatives, including a number of measures designed to increase employee understanding of First Nations culture and values. These efforts will continue in 2001 and will be expanded by the addition of new employees dedicated to First Nations relations.

The Corridor Pipeline project passes through 300 km of traditional lands of First Nations and Metis communities in northern Alberta. A plan was developed to enable the communities to work together and undertake clearing of 235 km of pipeline right-of-way. This project was managed and executed by Aboriginals, providing benefits for their people and their communities. This was a successful endeavour for Corridor and its First Nations and Metis stakeholders.

FINANCIAL REVIEW

Management Discussion and Analysis

This discussion and analysis is a review of the operating results, business risks, financial condition and outlook for BC Gas Inc. (BC Gas or the Company). This discussion should be read in conjunction with the consolidated financial statements of the Company and related notes.

OVERVIEW

BC Gas continued to deliver on its financial targets and strategic plans in 2000. Operating results improved in both the natural gas distribution and petroleum transportation businesses, the Southern Crossing Pipeline was completed on time and on budget and construction of the Corridor Pipeline was started. More than \$1.2 billion in new financing was raised to support these projects and other financing requirements. Financially, BC Gas met its targets by delivering growth in continuing earnings per share of 6% in 2000, combined with a return on equity of 12% before non-recurring items.

BUSINESS SEGMENTS OF BC GAS

NATURAL GAS DISTRIBUTION

The Company's natural gas distribution operations consist primarily of BC Gas Utility Ltd. (BC Gas Utility or the Utility) and several small related utility operations. BC Gas Utility is the largest distributor of natural gas in British Columbia, serving 762,000 customers in more than 100 communities. BC Gas Utility provides transmission and distribution services to its customers, and obtains gas supplies primarily on behalf of residential and commercial customers, making the Utility the largest single buyer of natural gas in the province. Gas supplies are sourced primarily from northeastern British Columbia and, through the new Southern Crossing Pipeline, from Alberta. Major areas served are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of the province.

PETROLEUM TRANSPORTATION

BC Gas' petroleum transportation operations are carried out by Trans Mountain Pipe Line Company Ltd. (Trans Mountain), which owns and operates a pipeline system transporting crude oil and refined products from Edmonton, Alberta to Burnaby, British Columbia. The pipeline of a U.S. subsidiary delivers Canadian crude oil to several refineries in Washington State. In addition, Trans Mountain owns and operates a marine terminal in the Port of Vancouver and a jet fuel pipeline to a storage system at Vancouver International Airport. Through Corridor Pipeline Limited, the Company is constructing a dual pipeline system with an estimated cost of \$688 million which will transport diluted bitumen and diluent between Fort McMurray and Edmonton, Alberta.

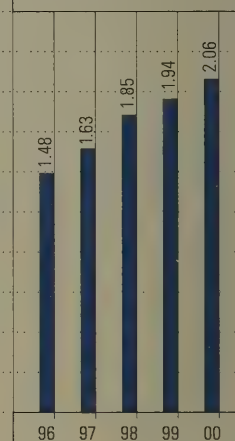
OTHER ACTIVITIES

BC Gas has other activities, which include non-regulated energy and utility businesses as well as corporate interest and administration charges. The non-regulated businesses include water supplies and services and international consulting. Until October 19, 1999, these businesses also included independent power production through NW Energy (Williams Lake) Limited Partnership (NW Energy). The majority of these businesses are direct subsidiaries of BC Gas.

The contribution to earnings per share of each segment is as follows:

Years ended December 31	2000	1999
Natural gas distribution	\$ 1.53	\$ 1.35
Petroleum transportation	0.56	0.51
Other activities	(0.03)	0.08
Earnings before non-recurring items	2.06	1.94
Non-recurring items	0.78	0.18
Earnings per common share	\$ 2.84	\$ 2.12

BC GAS INC.
Earnings Per Share Before
Non-Recurring Items
(dollars)

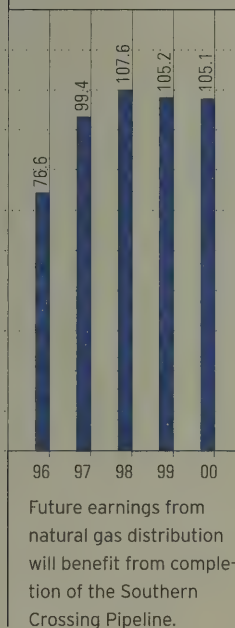


BC Gas met its earnings per share growth target again in 2000.

Management Discussion and Analysis

NATURAL GAS DISTRIBUTION

Earnings Before
Income Taxes and
Non-Controlling Interest
(\$ millions)



Non-recurring items of \$0.78 per share in 2000 are comprised of three items. \$0.76 per share in 2000 and \$0.18 per share in 1999 arose from income tax benefits associated with NW Energy which the company monetized in 1999. A gain of \$0.22 per share resulted from the effect of income tax rate reductions in calculating future income tax liabilities. Offsetting these benefits is an after tax charge of \$0.20 per share associated with restructuring costs at Trans Mountain Pipe Line.

EARNINGS PERFORMANCE

Earnings before non-recurring items were \$78.8 million in 2000 compared to \$74.2 million in 1999. An analysis of the increase in earnings is as follows:

In millions of dollars

Earnings applicable to common shares for 1999	\$ 81.2
1999 non-recurring item	
Income tax benefits from NW Energy	(7.0)
Earnings before non-recurring items for 1999	74.2
Natural Gas Distribution	
Higher allowed return on common equity in 2000	1.4
Earnings from higher capital expenditures	5.2
Higher revenues and other items	0.4
Petroleum Transportation	
Higher throughput and reduced operating costs	1.8
Other Activities	
Higher revenues and operating efficiencies	0.7
Utilization of tax losses carried forward in 1999	(4.9)
Earnings before non-recurring items for 2000	78.8
2000 non-recurring items	
Income tax benefits from NW Energy	29.0
Gain from future income tax rate reductions	8.5
Restructuring costs	(7.5)
Earnings applicable to common shares for 2000	\$ 108.8

NATURAL GAS DISTRIBUTION

CONTRIBUTION TO EARNINGS

In millions of dollars	2000	1999
Revenues	\$1,085.4	\$ 844.7
Operating expenses		
Cost of natural gas	658.4	442.2
Operation and maintenance	124.4	115.4
Depreciation and amortization	67.1	62.5
Property and other taxes	33.7	31.9
	883.6	652.0
Operating income	201.8	192.7
Financing costs	96.7	87.5
Earnings before income taxes and non-controlling interest	\$ 105.1	\$ 105.2

REVENUES

Revenues from natural gas distribution increased to \$1,085.4 million during 2000 from \$844.7 million in 1999. Revenues are set to recover the Utility's cost of service, the largest component of which is the cost of natural gas. In 2000, revenues were higher primarily as a result of increases in the cost of natural gas as well as increases in other operating and financing costs, all of which are flowed through into customer rates.

During 2000, 7,495 new customers were added, bringing the total number of gas utility customers to 762,878 at year end. The rate of customer additions decreased from 1999, when 13,078 new customers were added. These customer additions were mainly in the heating market for new single-family houses.

Industrial sales service increased by 1,721 terajoules while transportation volumes decreased by 2,998 terajoules from the previous year. The Utility earns approximately the same margin regardless of whether a customer contracts for sales or transportation service. The net reduction in industrial volumes reflected fuel switching by industrial customers that have dual-fuel capability as well as reduced energy consumption as market prices for natural gas increased late in 2000.

Management Discussion and Analysis

EXPENSES

Expenses for natural gas distribution include the cost of natural gas, operation and maintenance expenses, depreciation and amortization, and property and other taxes. Total operating expenses were \$883.6 million in 2000 compared with \$652.0 million in 1999.

Cost of natural gas amounted to \$658.4 million in 2000 compared with \$442.2 million in 1999. The increase in cost of gas reflects a dramatic increase in the market price of natural gas throughout North America. These higher market prices were reflected in an increase in the price of natural gas purchased by the Utility on behalf of its customers, which is flowed through into customer rates.

Operation and maintenance expenses increased to \$124.4 million in 2000 from \$115.4 million in 1999. This increase was due largely to a decrease in the ratio of overheads capitalized from 20% in 1999 to 16% in 2000 as part of the Utility's 1998-2000 revenue requirement settlement.

Increased investment in gas plant in service resulted in depreciation and amortization expense rising to \$67.1 million in 2000 from \$62.5 million in 1999. Growth in the asset base of the Company also resulted in property and other taxes increasing by \$1.8 million to \$33.7 million in 2000.

Financing costs increased to \$96.7 million in 2000 from \$87.5 million in the previous year largely as a result of higher debt balances due to rate base growth and higher short-term interest rates during 2000.

REGULATION AND RATES – BC GAS UTILITY

BC Gas Utility is regulated by the British Columbia Utilities Commission (the BCUC), which approves rates for services and the construction of facilities. In the past, rates have been set using the traditional rate base and rate of return approach to utility regulation. Since 1996, incentive-based

regulation has been incorporated into the rate setting process in order to enhance both value to customers and returns to shareholders.

The Utility's rates are based on estimates of a number of items, such as natural gas sales, cost of operations, cost of natural gas and interest rates. In order to manage the risks associated with some of these estimates, a number of regulatory deferral accounts are in place. The three most significant deferral accounts relate to the risks of weather, cost of natural gas, and interest rates.

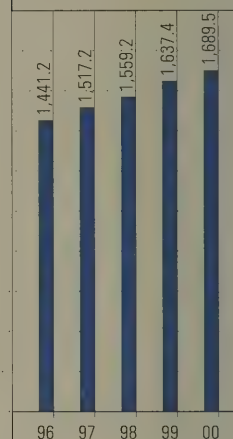
The deferral accounts for weather and cost of natural gas (which are also referred to as the rate stabilization accounts) reduce the Utility's earnings exposure to these risks by deferring any variances between projected and actual gas consumption and gas costs, and refunding or recovering those variances in future customer rates. Transportation and sales services to industrial customers are not covered by these deferral accounts. As a result of these deferral accounts, changes in reported revenues from year to year are caused mainly by changes in gas costs and other components of the Utility's cost of service which are recovered in customer rates. Changes in volumes of gas sold to residential and commercial customers due to weather or other factors have a less significant impact on reported revenues.

Due primarily to increases in market prices for natural gas during 2000, the balances receivable from customers under the rate stabilization accounts increased from \$32.8 million as at December 31, 1999 to \$150.1 million as at December 31, 2000. The recovery of these balances is approved by the BCUC. These balances are currently being amortized over three years.

BC Gas Utility also has in place short-term and long-term interest deferral accounts to absorb interest rate fluctuations. The Utility's interest deferral accounts effectively locked in the cost of short-term funds attributable to regulated assets at 6% during 2000, as compared to 5% in 1999.

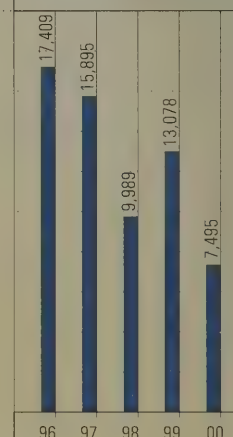
NATURAL GAS DISTRIBUTION

Rate Base
(\$ millions)



Rate base will increase significantly in 2001 when the Southern Crossing Pipeline is included.

NATURAL GAS DISTRIBUTION Customer Additions



Future customer additions may be affected by higher natural gas prices.

Management Discussion and Analysis

Allowed Return on Equity (ROE)

The Utility's 2000 allowed ROE of 9.50% was determined based on a formula that applied a risk premium to a forecast of long-term Government of Canada bond yields.

The increase from 9.25% in 1999 was a result of an increase in forecast long-term bond yields. For 2001, the Utility's allowed ROE has been set at 9.25%, reflecting lower forecasted long-term bond yields compared to the 2000 ROE calculation.

1998-2000 Revenue Requirement Decision

In June 1997, the Utility and other interested parties reached a negotiated settlement to set the revenue requirements for the Utility for the years 1998-2000, which was approved by the BCUC on July 23, 1997. During 2000, BC Gas negotiated a one year extension of the 1998-2000 settlement with customer representatives and other stakeholders. The one year extension was approved by the BCUC on May 4, 2000.

The key points of the settlement and extension are as follows:

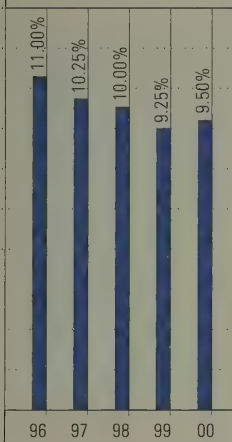
- Targets were set for productivity gains in operation and maintenance costs of 2% in each of 1998 and 1999, 3% in 2000 and 1% in 2001. To the extent that these productivity targets are exceeded, the Utility has the opportunity to earn higher returns on equity. Restructuring costs of up to \$3 million associated with achieving these productivity targets were deferred and recovered in customer rates. By implementing a restructuring program and other initiatives, the Utility has taken steps to reach and exceed these productivity targets in each year of the settlement.

- New incentives for demand side management activities and capital expenditure efficiency were made available. To the extent that demand side management programs exceed targets, and to the extent that unit costs of certain classes of capital expenditures are lower than the allowed level, the Utility has opportunities to earn higher returns. These incentives have not had a material impact on earnings.
- An earnings sharing mechanism is incorporated whereby variances in achieved return on equity from that allowed by the BCUC in a given year are to be shared equally with customers. Earnings from the established incentive programs are not included in this earnings sharing mechanism. This incentive has resulted in significant positive benefits for both customers and shareholders.
- The ratio of overheads capitalized has been reduced from 22.5% of gross operation and maintenance costs in 1997 to 20% in 1998 and 1999, and to 16% in 2000.
- The allowed common equity component is to remain at 33% of capitalization, and \$150 million of outstanding first preference shares were redeemed and have been refinanced with long-term debt in 1999 and 2000.
- Through an annual review process, rates for the upcoming year are adjusted to reflect projected changes in factors such as customer growth, industrial revenues, cost of natural gas, interest rates and taxes.

In addition to the incentives noted above, the Gas Supply Mitigation Incentive Plan provides an incentive for the Utility to reduce gas supply costs to customers.

NATURAL GAS DISTRIBUTION

Allowed Return on Equity



Reductions in the allowed ROE since 1996 reflect declines in Canadian interest rates.

Management Discussion and Analysis

During 2001, the Company intends to work with stakeholders to develop an improved incentive regulatory arrangement, which can more closely align the interests of customers with shareholders and provide the Company with additional incentives to create value for customers and improve returns to shareholders.

Southern Crossing Pipeline Project

In 1999, the BCUC granted a Certificate of Public Convenience and Necessity (CPCN) to BC Gas Utility for the Southern Crossing Pipeline (SCP) project. The SCP includes 303 kilometres of 24 inch (610 mm) pipeline from Yahk, B.C. in the south-eastern corner of the province to Oliver, B.C. at the south end of the Okanagan Valley, as well as related compression facilities. The pipeline was put into service on November 29, 2000. To December 31, 2000, \$350.4 million has been spent on the project. Including restoration and right of way repair costs and contingencies that will be incurred in 2001, BC Gas currently expects that total costs will be approximately \$410 million.

As part of the approval from the BCUC, project costs that exceed a threshold amount will not be included in rate base. This requirement will not have a material impact on the Company's earnings, provided that total project costs do not exceed \$410 million.

Unbundling

Over the past several years, the Company, the BCUC and a number of interested parties have been exploring options to provide increased customer choice to residential and smaller commercial users for their natural gas commodity purchases. Currently, these customers can only purchase their gas supplies from BC Gas. The Company is working with stakeholders to ensure that unbundling proceeds in a manner that does not expose the customers

of the Company to increased risk. The BCUC's target date for implementing unbundling is currently November 1, 2002. The Company does not anticipate that the introduction of these arrangements will have a material impact on the Company's financial results.

BUSINESS RISKS

Regulatory Treatment

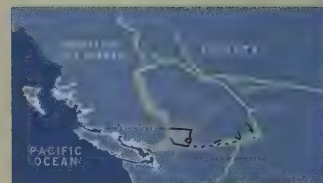
Through the regulatory process, the BCUC approves the return on equity which the Utility is allowed to earn, in addition to various other aspects of the Utility's operation. Fair regulatory treatment that allows the Utility to earn a risk adjusted rate of return comparable to that available on alternative investments is essential for ongoing success.

Long-Term Competitiveness

The unprecedented increase in the market price of natural gas in 2000 has significantly eroded the competitive advantage of natural gas relative to alternative sources of energy, notably electricity, in British Columbia. Because electricity prices in British Columbia continue to be set based on the cost of production, rather than based on market forces, they have remained artificially low. Over time, these pricing signals may distort energy use decisions by British Columbia consumers.

Notwithstanding the significant increase in gas commodity prices, at current relative prices for natural gas as of January 1, 2001, the Company does not anticipate that existing residential customers will find it economical to switch to electricity. However, the Company does anticipate that customers may reduce gas consumption through energy efficiency measures.

In addition, the Company anticipates that margin from industrial customers may decline as a result of customers with dual-fuel capability switching to alternative sources of energy or making investments in alternative energy systems. In an order dated



NATURAL GAS DISTRIBUTION

LEGEND

- BC GAS UTILITY LTD. TRANSMISSION PIPELINES
- SOUTHERN CROSSING PIPELINE
- BC GAS UTILITY LTD. DISTRIBUTION SERVICE AREA
- OTHER NATURAL GAS TRANSMISSION PIPELINES

Management Discussion and Analysis

December 28, 2000, however, the BCUC noted that BC Gas Utility could apply for regulatory relief should industrial margins fall significantly below forecast levels.

Should market prices for natural gas remain near current levels, strong incentives will exist for producers to develop additional supplies of natural gas, which would help to alleviate pricing pressures. However, natural gas prices in British Columbia are likely to continue to be influenced by demand for natural gas and electricity elsewhere in North America.

Customer Additions

New customer additions at BC Gas Utility are typically a result of population growth and new housing starts, which are affected by the state of the provincial economy. The current relative prices of natural gas versus electricity may have a negative impact on the choice of natural gas for new construction and therefore may affect customer additions.

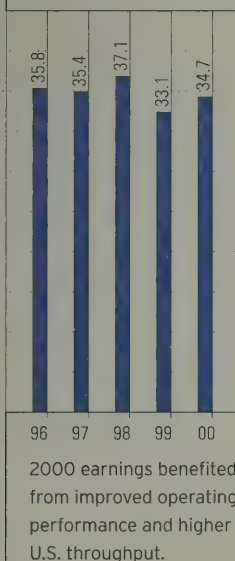
Gas Supply

By successfully bringing the Southern Crossing Pipeline into service, BC Gas has improved the security and competitiveness of the gas supply arrangements in place for BC Gas' customers. To the extent possible, BC Gas Utility has also attempted to minimize gas supply and price risk through the use of long-term transportation, storage and supply contracts, hedging instruments and a diverse supply portfolio.

However, recent market prices have demonstrated that insufficient pipeline capacity exists to serve the increasing demand for natural gas in B.C. and the U.S. Pacific Northwest that has arisen from heating requirements and gas-fired electricity generation. In addition, BC Gas continues to be dependent on a limited selection of pipeline and storage providers, particularly in the Vancouver-Lower Mainland service area where the majority of BC Gas Utility's core market customers are located. BC Gas is actively exploring opportunities to cost-effectively expand pipeline capacity to the Lower Mainland.

PETROLEUM TRANSPORTATION

Earnings before Restructuring Costs, Income Taxes and Non-Controlling Interest (\$ millions)



PETROLEUM TRANSPORTATION

CONTRIBUTION TO EARNINGS

In millions of dollars	2000	1999
Revenues	\$ 132.5	\$ 129.4
Operating expenses		
Operation and maintenance	47.0	46.8
Depreciation and amortization	17.7	15.4
Property and other taxes	18.1	19.3
	82.8	81.5
Operating income	49.7	47.9
Financing costs	15.0	14.8
Earnings before restructuring costs, income taxes and non-controlling interest	\$ 34.7	\$ 33.1

REVENUES

Revenues from petroleum transportation operations increased to \$132.5 million in 2000 from \$129.4 million in 1999 as a result of higher U.S. delivery volumes in 2000 compared to 1999 and higher mainline tolls. Pipeline deliveries averaged 35,682 cubic metres per day (m³/d) in 2000 compared to 36,184 m³/d in 1999.

As discussed below under Regulation, Trans Mountain's Canadian mainline was subject to a regulatory settlement that mitigated the impact of variations in throughput volumes on revenues and earnings. However, the U.S. pipeline in Washington State is not subject to the same regulatory arrangements, and fluctuations in U.S. mainline throughput have a direct impact on petroleum transportation revenues and earnings.

Overall throughput levels in 2000 were similar to those experienced in 1999; U.S. mainline throughput increased by 5%. As was the case in 1999, throughput levels in 2000 were influenced by strong refined product margins in the Pacific Northwest and by favourable crude oil price differentials between Canadian and alternative offshore supply sources.

Management Discussion and Analysis

EXPENSES

Operation and maintenance expense increased from \$46.8 million in 1999 to \$47.0 million in 2000. Under Trans Mountain's 1996-2000 incentive toll settlement, 50 per cent of operating efficiencies are shared with the shippers. The provision for the shipper's share of these benefits is recorded in operation and maintenance expense. Because of the reduction in property and other taxes in 2000, the provision for efficiency sharing with the shippers correspondingly increased. This, combined with higher fuel and power costs associated with higher throughput levels, more than offset the reduction in operation and maintenance costs that was achieved in 2000 from Trans Mountain's cost savings initiatives.

Property and other taxes declined from \$19.3 million in 1999 to \$18.1 million in 2000 as a result of property tax reassessments initiated by Trans Mountain during 2000. Financing costs in 2000 were \$15.0 million, compared to \$14.8 million in 1999 as a result of higher interest rates.

REGULATION

The National Energy Board (the NEB) regulates the Canadian portion of Trans Mountain's crude oil and refined products pipeline system. The NEB authorizes pipeline construction and establishes tolls and conditions of service. Traditionally, rates have been set using the historical cost rate base and a rate of return.

In 1995, Trans Mountain and shipper representatives reached a negotiated agreement that was approved by the NEB. That agreement determined Trans Mountain's revenue requirement, and resulting tolls, over a five year period which ended on December 31, 2000. The negotiated settlement contained an efficiency incentive that allowed Trans Mountain to retain 100% of earnings up to \$13.6 million in 2000, after

which earnings were shared 50/50 with the shippers. In 2000, the total pre-tax revenues to be returned to the shippers under this sharing arrangement were \$4.8 million. In addition, under the 1996-2000 incentive toll settlement, throughput volume risk was assumed by the shippers. Due to higher than forecast revenues earned in 2000, Trans Mountain will return \$0.4 million to the shippers in 2001 tolls.

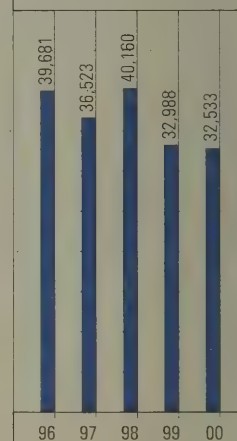
In November 2000, Trans Mountain and shipper representatives reached a negotiated agreement to determine Trans Mountain's tolls for the period 2001-2005. The agreement is subject to approval from the NEB, which is expected in the first half of 2001.

The 2001-2005 incentive toll settlement fixes tolls on Trans Mountain's Canadian mainline for the term of the settlement as long as throughput remains within a band of 28,500 to 32,000 m³/day. Tolls have been set using a base throughput level of 30,000 m³/day. Any revenue shortfalls arising from annual throughput levels below 28,500 m³/day will be recovered from the shippers. Incremental revenues arising from annual throughput above 32,000 m³/day will be shared 50/50 between Trans Mountain and the shippers. The fixed tolls will not escalate with inflation unless Canadian inflation rates increase above 3.5%, and Trans Mountain will keep all of the benefits achieved through productivity initiatives and operating efficiencies.

The toll charged for the U.S. pipeline in Washington State falls under the jurisdiction of the Federal Energy Regulatory Commission (FERC). Regulation by FERC is on a complaint basis. There were no complaints in 2000.

Tolls for the jet fuel pipeline system are regulated by the BCUC. In 1997, Trans Mountain conducted negotiations with the principal shippers on the jet fuel pipeline system. Those negotiations resulted in an agreement to determine the jet fuel pipeline revenue requirement in a manner substantially similar to the 1996-2000

**PETROLEUM
TRANSPORTATION**
Canadian Mainline
(Including U.S. Mainline)
(cubic metres per day)



The 2001 to 2005 incentive toll settlement uses a base throughput of 30,000 m³/day.

Management Discussion and Analysis

incentive toll settlement for the crude oil and refined products pipeline. The agreement began to operate for a five year period on January 1, 1998.

CORRIDOR PIPELINE LIMITED

Trans Mountain and the Company have entered into an agreement with Shell Canada Limited (Shell), Chevron Canada Resources Limited and Western Oil Sands Inc. for the construction and operation of the Corridor pipeline system. Corridor Pipeline Limited (Corridor) has been established as a direct subsidiary of the Company to own and operate this system.

The Corridor pipeline system will provide for the pipeline transportation of diluted bitumen produced at the Muskeg River Mine located approximately 70 km north of Fort McMurray, Alberta to a heavy oil upgrader that Shell and its partners plan to construct adjacent to Shell's existing Scotford Refinery near Edmonton, Alberta, a distance of approximately 453 km. A smaller diameter parallel pipeline will transport recovered diluent from the upgrader back to the mine. Corridor will also construct two additional pipelines, each 43 km in length, to provide pipeline transportation between the proposed Scotford Upgrader and the existing trunk pipeline facilities of Trans Mountain and Enbridge in the Edmonton area. The completed pipeline system is estimated to cost \$688 million.

The estimated cost is divided into two parts. \$460 million is a fixed price, quoted to Shell and its partners by the Company. It contains fixed price bid amounts from third party contractors, a contingency amount and amounts estimated by Corridor, and is subject to certain agreed escalators. The balance of the cost, which includes line fill and interest costs, is comprised of amounts over which Corridor has no control or risk exposure, and which will be included in the rate base at cost.

The Corridor pipeline project has received all required regulatory approvals in addition to approvals from Shell and its partners. Construction is underway, and the project is proceeding on schedule and within budget. To December 31, 2000, \$137.3 million has been spent on the project, including capital expenditures and deferred charges. Shell and its partners have made a long term take or pay commitment to transport a total of 150,000 barrels per day of bitumen and 65,000 barrels per day of diluent in the Corridor pipeline system.

BUSINESS RISKS

Competitiveness

Trans Mountain's pipeline to the West Coast of North America is one of several alternatives for Western Canadian petroleum production. Throughput may decline in situations where West Coast prices are relatively lower than alternative prices in the U.S. Midwest.

Refined products can be imported for the British Columbia market through marine offloading facilities in the Port of Vancouver or by truck transportation from refineries in Washington State. In 2000, refined products for the British Columbia market represented approximately 39.7% of Trans Mountain's deliveries.

Revenues are affected by changes in throughput volumes. Under the incentive toll settlement for the Canadian mainline, this risk is mitigated by a mechanism that permits Trans Mountain to recover revenue shortfalls arising from throughput below 28,500 m³/day in subsequent years. However, recovery of any accumulated shortfall depends on sufficient throughput in subsequent years. Revenues associated with throughput on the U.S. pipeline are not covered by the incentive toll settlement, and are therefore directly affected by changes in U.S. throughput.



PETROLEUM TRANSPORTATION

LEGEND

- TRANS MOUNTAIN PIPELINE
- CORRIDOR PIPELINE
- OTHER OIL PIPELINES

Management Discussion and Analysis

Power Costs

Ongoing deregulation of the electrical power industry in Alberta may result in significantly increased power costs. Trans Mountain is actively managing its power supply arrangements with the intention of mitigating the effect of power cost increases.

Negative Salvage Value

The cost of abandonment of the pipeline system at the eventual end of its useful life may not be fully recovered in tolls. Until such time as the magnitude of and the funding mechanism for the eventual recovery of negative salvage is determined, Trans Mountain, like other Canadian trunk pipeline systems, makes no provision for these amounts.

Operations

Trans Mountain has taken all reasonable and prudent steps to minimize its exposure in the case of a catastrophic event or environmental upset. Trans Mountain maintains a comprehensive Line Integrity Program as a preventive measure to mitigate the risk of a pipeline failure or other loss of system integrity. The Program is intended to reduce both the likelihood and severity of the business interruption and/or environmental liability that could result from a loss of line integrity.

OTHER ACTIVITIES

CONTRIBUTION TO EARNINGS

In millions of dollars	2000	1999
Revenues	\$ 87.7	\$ 66.5
Operating expenses		
Operation and maintenance	24.0	20.7
Depreciation and amortization	1.4	5.2
Property and other taxes	0.2	1.3
Cost of revenues	57.0	24.0
	82.6	51.2
Operating income	5.1	15.3
Financing costs	5.8	19.3
Loss before income taxes and non-controlling interest	\$ (0.7)	\$ (4.0)

Losses from other activities in 2000 were \$0.7 million before income taxes and non-controlling interest compared with a loss of \$4.0 million in 1999. This improvement was mainly due to contributions from the Company's water supplies and services businesses and revenues from the second phase of construction of a natural gas distribution system in the United Arab Emirates city of Sharjah.

Although the monetization of NW Energy had a modest impact on the overall loss from other activities before income taxes and non-controlling interest, it resulted in a significant change in operating income, which was mostly offset by a corresponding reduction in financing costs.

Revenues increased from \$66.5 million in 1999 to \$87.7 million in 2000 primarily as a result of the acquisition of several water supplies and services businesses in 1999 and early 2000, offset by the monetization of NW Energy. Operation and maintenance expense increased \$3.3 million to \$24.0 million in 2000 for the same reasons. Depreciation and amortization and property and other taxes declined in 2000 as a result of the NW Energy monetization. Cost of revenues increased from \$24.0 million in 1999 to \$57.0 million in 2000 due to the acquisition of the water businesses.

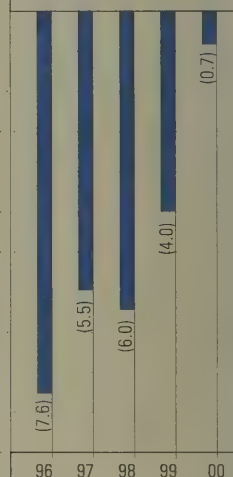
BCG EFUELS INC./

WESTPORT INNOVATIONS INC.

On October 31, 2000 BC Gas completed a financing agreement with Westport Innovations Inc. (Westport) to strengthen an alliance to build refuelling infrastructure for natural gas vehicles. Under the agreement, BC Gas invested \$8 million in common shares of Westport. In turn, Westport used the \$8 million proceeds to acquire a 32% interest in BCG eFuels Inc., a BC Gas subsidiary engaged in providing alternative fuel infrastructure and turnkey refuelling solutions for vehicles and fleets.

OTHER ACTIVITIES

Earnings Before
Income Taxes and
Non-Controlling Interest
(\$ millions)



The improvement in 2000 results reflects contributions from water supplies and services and from international consulting.

Management Discussion and Analysis

BUSINESS RISKS

The other activities segment is relatively less significant than the Company's two other segments. Businesses in this segment primarily operate in unregulated industries which are, by their nature, more risky than BC Gas' regulated operations. Therefore, earnings contributions from these businesses are less predictable. Factors such as economic conditions, interest rates, foreign exchange rates and market pricing conditions may impact the results from these businesses.

NON-RECURRING ITEMS

NW ENERGY MONETIZATION

On October 19, 1999, BC Gas sold its interest in the cash flow of NW Energy, which owns a wood waste-fired independent electricity generating plant, to TransCanada Power, L.P. BC Gas received net proceeds of \$25.6 million which, along with income tax benefits that were recognized in 1999 and 2000, resulted in a gain of \$7.0 million in 1999 and \$29.0 million in 2000. As at December 31, 2000, the Company no longer owns any interest in NW Energy.

INCOME TAX RATE REDUCTIONS

The reduction in Federal income tax rates reduces the value of future income tax assets and liabilities. The value of these changes is included in earnings in the year that the rate reduction is substantially enacted. The effect of the income tax rate reductions that were substantially enacted in 2000 is an increase in earnings of \$8.5 million.

RESTRUCTURING AND RELOCATION COSTS

The Company has recorded a provision of \$13.5 million (\$7.5 million after tax) for costs relating to restructuring and relocation programs of petroleum transportation operations which will be implemented in 2001.

LIQUIDITY AND CAPITAL RESOURCES

An increase in net earnings (after adjusting for items not involving cash) and changes in non-cash operating working capital and rate stabilization accounts resulted in an increase in cash flow from operating activities to \$179.3 million in 2000 from \$124.1 million in 1999.

Capital expenditures totaled \$620.6 million in 2000 compared with \$163.6 million in 1999. The \$457.0 million increase in capital spending was due mainly to expenditures on the Southern Crossing Pipeline and Corridor Pipeline projects.

The capital spending in 2000 is summarized as follows:

In millions of dollars

Natural gas distribution	
Mains, services and engineering projects	\$ 56.2
Land and buildings	31.6
Systems and computer hardware	29.9
Southern Crossing Pipeline	329.5
Capitalized overhead	23.3
Other	2.0
	472.5
Petroleum transportation	
Trans Mountain	13.0
Corridor Pipeline	127.6
	140.6
Other activities	7.5
Total	\$620.6

COVERAGE RATIOS

Due to the capital intensive nature of the Company's businesses and the need to raise debt frequently in the fixed income market, maintenance of its financial ratios is a priority for BC Gas. The most significant ratios are considered to be interest coverage and total debt to shareholders' equity. These are presented below on a consolidated basis

Management Discussion and Analysis

for BC Gas, BC Gas Utility and Trans Mountain. Coverage ratios for Corridor are not meaningful while the pipeline is under construction.

	2000	1999
Interest coverage		
BC Gas	2.18	2.10
BC Gas Utility	2.07	2.19
Trans Mountain	3.65	3.58
Debt to shareholders' equity		
BC Gas	2.50:1	2.44:1
BC Gas Utility	2.06:1	1.72:1
Trans Mountain	1.14:1	1.35:1

DEBT RATINGS

Securities issued by BC Gas, BC Gas Utility, Trans Mountain and Corridor are rated by two Canadian bond rating companies, the Dominion Bond Rating Service (DBRS) and the Canadian Bond Rating Service (CBRS). The ratings assigned to securities issued by the BC Gas group of companies are reviewed by DBRS and CBRS on an annual basis. During 2000, CBRS was acquired by Standard and Poor's (S&P). S&P is in the process of harmonizing CBRS ratings with S&P's global rating scale. S&P ratings for BC Gas, BC Gas Utility and Trans Mountain are expected to be harmonized during the first quarter of 2001.

The table below summarizes the ratings assigned to the Company's various securities at December 31, 2000.

	DBRS	CBRS
BC Gas Inc.		
Commercial paper	R-1 (Low)	A-1 (Low)
Corporate rating	A (Low)	-
Capital securities	BBB (High)	BBB
BC Gas Utility		
Commercial paper	R-1 (Low)	A-1
Unsecured debentures	A	A-
Medium term note debentures	A	A-
Purchase money mortgages	A	A
Trans Mountain		
Commercial paper	R-1 (Low)	A-1 (Low)
Unsecured debentures	A (Low)	A-
Corridor		
Commercial paper	R-1 (Low)	A-1 (Low)

PROJECTED CAPITAL EXPENDITURES

BC Gas has estimated total capital expenditures of \$552.7 million in 2001 for all of its subsidiaries. Expenditures on the Corridor Pipeline are being financed by commercial paper borrowings, which are supported by a credit facility from a syndicate of banks. The Company expects to finance other capital expenditures with a combination of long-term debt issuance at BC Gas Utility, short-term borrowings and internally generated funds. The breakdown of projected capital expenditures for 2001 is as follows:

In millions of dollars

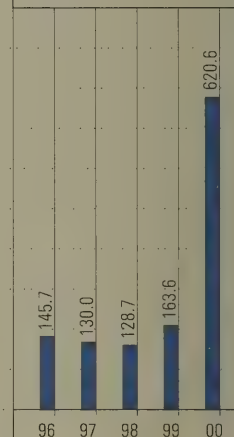
Natural gas distribution	
Mains, services and engineering projects	\$ 79.5
Land and buildings	1.6
Systems and computer hardware	35.5
Southern Crossing Pipeline	59.6
Capitalized overhead	23.4
Other	10.1
	209.7
Petroleum transportation	
Trans Mountain	19.0
Corridor Pipeline	300.0
	319.0
Other activities	24.0
Total	\$ 552.7

RATE STABILIZATION ACCOUNTS

As discussed under Regulation and Rates – BC Gas Utility, the rate stabilization accounts permit the Utility to recover the difference between projected and actual gas costs in future rates. However, increasing balances receivable from customers in the rate stabilization accounts create a financing requirement until the balances are recovered in customer rates. The Company expects to finance any further increases in rate stabilization account balances through debt issuance by BC Gas Utility.

BC GAS INC.

Consolidated Capital Expenditures (\$ millions)



2000 saw the largest capital expansion in BC Gas' history.

Management Discussion and Analysis

PUBLIC ISSUES

During the year, BC Gas Utility issued \$425 million of medium term note debentures at a weighted average interest rate of 6.35%. This compares with \$225 million issued in 1999 at an interest rate of 6.70%.

On April 19, 2000, BC Gas issued \$125 million of 8.0% Capital Securities to support the equity financing requirements of the Southern Crossing and Corridor pipeline projects.

LINES OF CREDIT

At December 31, 2000, the Company had lines of credit in place totaling \$1,375 million to finance cash requirements, comprising \$200 million at BC Gas, \$350 million at BC Gas Utility, \$125 million at Trans Mountain and \$700 million at Corridor. These lines enable the respective companies to borrow directly from their bankers, issue bankers' acceptances and support commercial paper issued by each company. Bank lines of \$860 million were unutilized at the end of 2000. Virtually all short-term cash needs are funded through commercial paper and bankers' acceptances in the Canadian market at rates generally below bank prime.

During February 2001, BC Gas Utility arranged for additional bank lines of credit totaling \$150 million. These bank lines were obtained primarily to finance potential increases in rate stabilization account balances.

DIVIDENDS

The dividends paid on BC Gas' common shares in 2000 were \$1.225 per share, up from \$1.165 per share in 1999. In aggregate, BC Gas paid common shareholder dividends of \$46.9 million in 2000 compared to \$44.6 million in 1999, reflecting the increased dividend per share.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company uses financial instruments from time to time to manage its exposure to changes in interest rates where the interest rate risk is not managed through the use of interest rate deferral accounts. These financial instruments are used only for hedging purposes, and are employed only in connection with an underlying asset or liability through counterparties with acceptable credit status. There were no interest rate hedging instruments in place at December 31, 2000.

BC Gas, through its natural gas distribution operations, has undertaken a natural gas price risk management program on behalf of its customers to manage the price volatility of its forecast system gas supply. Part of this program involves the use of financial instruments to effectively fix the price of baseload gas supply.

OTHER MATTERS

UNION SETTLEMENTS

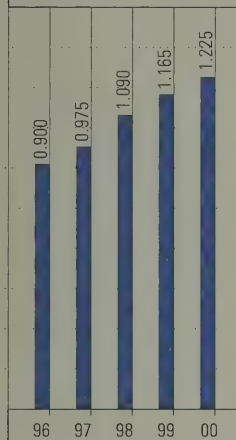
A collective agreement with BC Gas Utility employees represented by the Office and Professional Employees International Union (Local 378) expired March 31, 2000. Another collective agreement with BC Gas Utility employees represented by the International Brotherhood of Electrical Workers (Local 213) has an expiry date of March 31, 2001. Negotiations are continuing.

OUTLOOK

With construction underway on the Corridor Pipeline and construction complete on the Southern Crossing Pipeline, BC Gas is delivering on its strategic initiatives. BC Gas' earnings in 2000 delivered on the Company's financial targets. BC Gas is continuing to pursue growth initiatives that capitalize on its core competencies within its existing risk profile.

BC GAS INC.

Dividends Paid Per Share
(dollars)



Since 1996, dividends per share have grown by 36%.

Management Discussion and Analysis

The unprecedented increases in prices for natural gas present challenges for both the Company and its customers. BC Gas is actively managing its natural gas procurement activities on behalf of customers in order to minimize the cost that has to be flowed through to customers. However, new customer additions and industrial volumes may be negatively affected by high natural gas prices in the short term.

In natural gas distribution, BC Gas is pursuing a new multi-year regulatory settlement to take effect in 2002. In addition, the Company is actively developing proposals for new pipeline infrastructure to serve the growing demand for natural gas in the Pacific Northwest for use in electricity generation. These initiatives have the potential to deliver significant benefits for both customers and shareholders of BC Gas.

For petroleum transportation, the proposed Incentive Toll Settlement provides new incentives to maximize throughput and deliver increased efficiencies. The Corridor Pipeline positions the Company in the growth potential of the Alberta oil sands, and the relocation of Trans Mountain to Calgary will enhance the Company's ability to capture new opportunities in petroleum transportation. These initiatives in natural gas distribution and petroleum transportation are making significant contributions to BC Gas' strategic objective of strengthening and expanding its base businesses.

BC Gas is also making progress on its strategic initiative of developing its multi-utility businesses. The Company's water business acquisitions have added to its capabilities and the Company is actively pursuing opportunities that would allow it to move into water utility operations. The partnerships that have been created in the natural gas vehicle fuel business with Ford Motor Company and Westport Innovations will support future growth opportunities in this area.

BC Gas is committed to delivering on its earnings per share growth target while maintaining a low risk profile and focusing on the Company's core businesses. The Company is confident that it can achieve these objectives in the long term through efficient operations, infrastructure development and developing its multi-utility activities.

Management's Responsibility

The consolidated financial statements have been prepared by management, which is responsible for the integrity and objectivity of this information. These statements have been prepared in conformity with Canadian generally accepted accounting principles and, where appropriate, include some amounts that are based on management's best estimates and judgments. The financial information presented elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management has established systems of internal control which are designed to provide reasonable assurance that assets are safeguarded from loss and that reliable financial records are maintained. These systems are monitored by internal auditors.

KPMG LLP, the auditors appointed by the shareholders, have reviewed the systems of internal control and examined the consolidated financial statements in accordance with Canadian generally accepted auditing standards to enable them to express an independent opinion on the consolidated financial statements. Their report is set out below.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting and internal control. The Audit Committee meets with the internal auditors, the independent auditors and management to discuss auditing and financial matters and to review the consolidated financial statements and the independent auditors' report. The Audit Committee reports its findings to the Board for consideration in approving the consolidated financial statements for issuance to the shareholders.



John M. Reid
President and Chief Executive Officer



Milton C. Woensdregt
Senior Vice President, Finance,
Chief Financial Officer and Treasurer

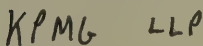
Vancouver, Canada
February 6, 2001

Auditors' Report

We have audited the consolidated statements of financial position of BC Gas Inc. as at December 31, 2000 and 1999 and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2000 and 1999 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles. As required by the Company Act (British Columbia), we report that, in our opinion, these principles have been applied consistently, after giving retroactive effect to the change in the method of accounting for income taxes and except for the change in method of accounting for employee future benefits as explained in the notes to the consolidated financial statements.



Chartered Accountants
Vancouver, Canada
February 6, 2001

Consolidated Statements of Earnings

(In millions of dollars, except per share amounts)

Years ended December 31	2000	1999
REVENUES		
Natural gas distribution	\$ 1,085.4	\$ 844.7
Petroleum transportation	132.5	129.4
Revenues from other activities	87.7	40.4
Electricity sales	—	26.1
	1,305.6	1,040.6
EXPENSES		
Cost of natural gas	658.4	442.2
Operation and maintenance	195.4	182.9
Depreciation and amortization	86.2	83.1
Property and other taxes	52.0	52.5
Cost of revenues from other activities	57.0	24.0
	1,049.0	784.7
OPERATING INCOME	256.6	255.9
Financing costs (note 8)	117.5	121.6
Restructuring costs (note 9)	13.5	—
Earnings before income taxes and non-controlling interest	125.6	134.3
Income taxes on earnings (note 10)	37.9	55.4
Income tax benefits from NW Energy (note 11)	(29.0)	(7.0)
	8.9	48.4
Earnings before non-controlling interest	116.7	85.9
Non-controlling interest (note 4)	4.0	4.7
NET EARNINGS	112.7	81.2
Capital securities distributions (note 5)	3.9	—
EARNINGS APPLICABLE TO COMMON SHARES	\$ 108.8	\$ 81.2
Common shares – weighted average (millions)	38.3	38.3
EARNINGS PER COMMON SHARE	\$ 2.84	\$ 2.12

Consolidated Statements of Retained Earnings

(In millions of dollars)

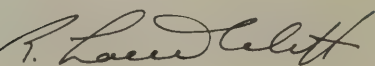
Years ended December 31	2000	1999
Retained earnings, beginning of year	\$ 183.2	\$ 147.2
Earnings applicable to common shares	108.8	81.2
	292.0	228.4
Dividends on common shares	46.9	44.6
Capital securities issue costs	2.7	—
Share options purchased (note 6)	1.7	0.6
	51.3	45.2
Retained earnings, end of year	\$ 240.7	\$ 183.2

Consolidated Statements of Financial Position

(In millions of dollars)

December 31	2000	1999
ASSETS		
Current assets		
Cash	\$ 22.4	\$ 5.6
Accounts receivable	460.4	178.5
Inventories of gas in storage and supplies	96.6	49.4
Prepaid expenses	6.8	4.4
Current portion of rate stabilization accounts	45.0	32.8
	631.2	270.7
Property, plant and equipment (note 1)	2,727.6	2,185.1
Rate stabilization accounts	105.1	—
Other assets (note 2)	49.2	25.1
	\$ 3,513.1	\$ 2,480.9
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term notes	\$ 387.0	\$ 452.0
Accounts payable and accrued liabilities	625.7	179.1
Income and other taxes payable	9.2	4.1
Current portion of long-term debt (note 3)	72.5	77.2
	1,094.4	712.4
Long-term debt (note 3)	1,561.9	1,001.8
Future income taxes	47.3	65.4
Non-controlling interest (note 4)	—	75.0
	2,703.6	1,854.6
Shareholders' equity		
Capital securities (note 5)	125.0	—
Common shares (note 5)	364.0	363.3
Contributed surplus	130.8	130.8
Retained earnings	240.7	183.2
	860.5	677.3
Less cost of common shares held by Trans Mountain	51.0	51.0
	809.5	626.3
	\$ 3,513.1	\$ 2,480.9

Approved by the Board:



Ronald L. Cliff
Director



John M. Reid
Director

Consolidated Statements of Cash Flows

(In millions of dollars)

Years ended December 31	2000	1999
Cash flows provided by (used for)		
Operating activities		
Net earnings	\$ 112.7	\$ 81.2
Adjustments for non-cash items		
Depreciation and amortization	86.2	83.1
Future income taxes	(18.1)	9.9
Other	(4.4)	0.2
	176.4	174.4
Increase in long-term rate stabilization accounts	(105.1)	—
Changes in non-cash operating working capital	108.0	(50.3)
	179.3	124.1
Investing activities		
Property, plant and equipment	(620.6)	(163.6)
Other assets	(27.8)	(4.3)
Net proceeds from disposal of NW Energy (note 11)	—	25.6
	(648.4)	(142.3)
Financing activities		
Decrease in short-term notes	(65.0)	(22.0)
Increase in long-term debt	558.6	231.7
Reduction of long-term debt	(3.2)	(135.2)
Reduction of non-controlling interest (note 4)	(75.0)	—
Issue of capital securities, net of issue costs	122.3	—
Issue of common shares and share options purchased	(1.0)	(0.3)
Dividends and distributions on common shares and capital securities	(50.8)	(44.6)
	485.9	29.6
Net increase in cash	16.8	11.4
Cash (bank indebtedness) at beginning of year	5.6	(5.8)
Cash at end of year	\$ 22.4	\$ 5.6
Supplemental disclosure of cash flow information		
Amount of interest paid in the year	\$ 114.6	\$ 120.6
Amount of income taxes recovered in the year	4.4	2.6

Cash is defined as cash and short-term investments or bank indebtedness

Significant Accounting Policies

The preparation of these consolidated financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts in the financial statements and the disclosure of contingent assets and liabilities. A significant area requiring the use of management estimates relates to the determination of useful lives for depreciation and amortization. The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below:

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its subsidiaries. The natural gas distribution operations are conducted through BC Gas Utility Ltd. ("the Utility"). The petroleum transportation operations are carried out through Trans Mountain Pipe Line Company Ltd. ("Trans Mountain") which owns and operates a common carrier pipeline system for crude and refined petroleum products and through Corridor Pipeline Limited ("Corridor") which has agreed to construct a pipeline in Northern Alberta to transport diluted bitumen.

Trans Mountain owns 10.7% (1999 – 10.7%) of the common shares of the Company. The cost of these shares is shown as a deduction from shareholders' equity.

These consolidated financial statements include the results of NW Energy (Williams Lake) Limited Partnership ("NW Energy") until October 19, 1999 (see note 11).

REGULATION

The Utility is subject to the regulation of the British Columbia Utilities Commission ("the Commission"). Trans Mountain's operations are regulated in Canada by the National Energy Board and, in the United States, tariff matters are regulated by the Federal Energy Regulatory Commission.

These regulatory authorities exercise statutory authority over such matters as rate of return, construction and operation of facilities, accounting practices, and rates and tolls. With respect to Corridor, these matters are governed by contractual arrangements with shippers and are subject to regulation by the Alberta Energy and Utilities Board.

INVENTORIES

Inventories of gas in storage and supplies are valued at cost determined mainly on a moving-average basis. Inventories of other supplies are valued at the lower of cost and net realizable value.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at cost which includes all direct costs, betterments, an allocation of overhead costs and an allowance for funds used during construction.

Depreciation of regulated assets is provided on a straight-line basis on plant in service at rates approved by regulatory authorities. The cost of depreciable property retired, together with removal costs less salvage, is charged to accumulated depreciation.

Depreciation of non-regulated equipment is provided using the declining balance method.

No provision for future removal and site restoration obligations has been accrued for regulated operations as the extent of such costs is not currently determinable. Management expects that such costs would be recoverable through future rates or tolls.

DEFERRED CHARGES

The Company defers certain charges which the regulatory authorities or contractual arrangements require or permit to be recovered through future rates or tolls. Deferred charges are amortized over various periods depending on the nature of the charges and include financing costs such as long-term debt issue costs which are amortized over the original lives of the related debt.

Deferred charges not subject to regulation relate to projects which may benefit future periods and will be capitalized on completion or expensed on abandonment of the projects. Amortization is provided on a straight-line basis over periods from 20 to 25 years.

GOODWILL AND INTANGIBLE ASSETS

Goodwill and intangible assets represent the excess of the purchase price over the fair value of the net assets acquired.

Goodwill and intangible assets are being amortized over 20 years. Management reviews on an ongoing basis the valuation and amortization of goodwill and intangible assets taking into consideration any events and circumstances which might have impaired the net book value. Goodwill and intangible assets are written down when declines in value are considered to be other than temporary based upon expected undiscounted cash flows of the entity to which the goodwill and intangible assets relate.

Significant Accounting Policies

RATE STABILIZATION ACCOUNTS

The Utility is authorized by the Commission to maintain two rate stabilization accounts to mitigate the effect on its earnings of unpredictable and uncontrollable factors, principally temperature and cost of natural gas fluctuations.

The gas cost reconciliation account ("GCRA") accumulates unforecasted changes in natural gas costs and natural gas cost recoveries. The revenue stabilization adjustment mechanism ("RSAM") accumulates the margin impact of variations in the actual use for residential and commercial customers from forecast use. The balances are amortized as approved by the Commission.

REVENUES

Revenue from natural gas sales is recorded by the distribution utilities on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the reporting period.

Revenue from the sale of electricity was recognized as electricity was generated at rates established in an agreement between NW Energy and British Columbia Hydro and Power Authority ("BC Hydro"). The price that was paid by BC Hydro consisted of a monthly Firm Energy Component and other monthly components to recover certain operating costs subject to certain maximum amounts which were adjusted for inflation.

EMPLOYEE BENEFIT PLANS

On January 1, 2000 the Company adopted the provisions of Section 3461 of the Canadian Institute of Chartered Accountants ("CICA") Handbook, which requires that the Company accrue its obligations under employee benefit plans and the related costs, net of plan assets, as the underlying services are provided. The cost of pensions and other retirement benefits earned by employees is actuarially determined using the projected benefit method prorated on services and reflects management's best estimates of expected plan investment performance, salary growth, future terminations, expected health care costs, mortality rates and retirement ages of plan members. For the purpose of calculating the expected return on plan assets, those assets are valued at fair value. Adjustments that result from plan amendments, changes in assumptions and experience gains and losses are amortized over the expected average remaining service life of the employee group covered by the plan. A current settlement discount rate is used to measure the accrued pension benefit obligation instead of using a long-term rate of return.

The Company has adopted this new standard on a prospective basis. The estimated amount of the non-pension post employment benefit obligation at January 1, 2000 was \$26.7 million as calculated by an independent actuary. This transition obligation is being amortized together with current service costs, interest costs and actuarial losses over the expected average remaining service lifetime of employees who are active as of the transition date. Adoption of the new standard had no significant impact on net earnings as the cost of providing pension and post employment benefits continues to match the recovery of these costs in rates.

INCOME TAXES

The Company's regulated subsidiaries account for income taxes for regulated operations as prescribed by their respective regulatory authorities. This includes following the taxes payable method of accounting for income taxes and accounting for certain assets and the rate stabilization accounts on a net of realized tax savings basis as approved by the Commission. This method is followed as there is reasonable expectation that all taxes payable in future years will be recoverable from customers at that time. On January 1, 2000 the Company adopted the provisions of Section 3465 of the CICA Handbook which continues to allow the Company's regulated subsidiaries to follow the taxes payable method.

The Company and its other non-regulated subsidiaries will now follow the asset and liability method of accounting for future income taxes required by the new standard. Under this method, future income taxes are determined based on differences between the accounting and tax basis of assets and liabilities. In prior years, the deferral method of accounting for income taxes was followed.

This change has been applied retroactively and results in an increase in property, plant and equipment of \$30.4 million as at December 31, 1999 and a corresponding increase in future income taxes, formerly the deferred income tax liability, in the statements of financial position. The new standard has no impact on retained earnings as at January 1, 1999 or on net earnings for 1999.

SHARE BASED COMPENSATION

The Company has a common share option plan which is described in note 6. No compensation expense is recognized for the share option plan when the options are issued. Any consideration paid by employees on the exercise of the share option is credited to common shares while consideration paid to repurchase share options from participants is charged to retained earnings, net of the related income taxes.

Notes to Consolidated Financial Statements

(Tabular amounts in millions of dollars, except per share amounts)

Years ended December 31, 2000 and 1999

1. PROPERTY, PLANT AND EQUIPMENT

2000				
	Depreciation rates	Cost	Accumulated depreciation	Net book value
Natural gas and petroleum pipeline systems	1% – 10%	\$ 2,859.1	\$ 585.9	\$ 2,273.2
Pipeline under construction	0%	127.6	—	127.6
Plant, buildings and equipment	1% – 33%	324.7	112.5	212.2
Land and land rights	0% – 5%	115.8	1.2	114.6
		\$ 3,427.2	\$ 699.6	\$ 2,727.6

1999

	Depreciation rates	Cost	Accumulated depreciation	Net book value
Natural gas and petroleum pipeline systems	1% – 10%	\$ 2,427.8	\$ 533.7	\$ 1,894.1
Plant, buildings and equipment	1% – 33%	303.7	118.4	185.3
Land and land rights	0% – 5%	106.9	1.2	105.7
		\$ 2,838.4	\$ 653.3	\$ 2,185.1

The composite depreciation rate on regulated property, plant and equipment for the year ended December 31, 2000 is approximately 3.0% (1999 – 3.0%).

2. OTHER ASSETS

	2000	1999
Deferred charges		
Subject to regulation	\$ 26.3	\$ 18.4
Not subject to regulation	3.2	1.6
	29.5	20.0
Investments	8.9	1.3
Goodwill and intangible assets	8.7	1.7
Long-term receivables	2.1	2.1
	\$ 49.2	\$ 25.1

Notes to Consolidated Financial Statements

3. LONG-TERM DEBT

	2000	1999
BC GAS UTILITY LTD.		
(a) Purchase Money Mortgages:		
11.80% Series A, due September 30, 2015	\$ 74.9	\$ 75.0
10.30% Series B, due September 30, 2016	200.0	200.0
(b) Debentures:		
9.75% Series D, due December 17, 2006	20.0	20.0
10.75% Series E, due June 8, 2009	59.9	59.9
8.50% Series F, due August 26, 2002	100.0	100.0
8.15% Series H, due July 28, 2003	50.0	50.0
(c) Medium Term Note Debentures:		
6.20% Series 9, due June 2, 2008	188.0	188.0
5.10% Series 10, due February 2, 2001	50.0	50.0
6.95% Series 11, due September 21, 2029	150.0	150.0
6.50% Series 12, due July 20, 2005	200.0	—
6.50% Series 13, due October 16, 2007	100.0	—
6.00% Series 14, due October 23, 2003	50.0	—
6.00% Series 15, due December 11, 2002	75.0	—
Various series, weighted average interest rate of 8.74% (1999 – 8.74%) with maturities ranging from 2001 to 2005	65.0	65.0
Obligations under capital leases, at 6.00% (1999 – 6.43%)	13.7	11.2
	1,396.5	969.1
TRANS MOUNTAIN PIPE LINE COMPANY LTD.		
(d) Debentures:		
9.75% Series A, due February 18, 2002	44.9	44.9
10.75% Series B, due November 22, 2004	30.0	30.0
11.50% Series C, due June 20, 2010	35.0	35.0
	109.9	109.9
CORRIDOR PIPELINE LIMITED		
(e) Commercial Paper at short-term floating rates, weighted average interest rate of 5.75%	128.0	—
Total long-term debt	1,634.4	1,079.0
Less current portion of long-term debt	72.5	77.2
	\$ 1,561.9	\$ 1,001.8

(a) Purchase Money Mortgages:

The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on the Utility's Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to \$425 million.

During 2000, holders of \$74.9 million of the 11.80% Series A Purchase Money Mortgages originally due on September 30, 2000 exercised their option to extend them to September 30, 2015 at a rate of 11.80%.

(b) BC Gas Utility Debentures:

The BC Gas Utility debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

(c) Medium Term Note Debentures:

The Utility's Medium Term Note Debentures are unsecured obligations but are subject to the terms of the Trust Indenture dated November 1, 1977 (see note 3(b)).

Notes to Consolidated Financial Statements

(d) Trans Mountain Debentures:

The Trans Mountain debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated February 18, 1987, as amended and supplemented.

(e) Commercial Paper:

The commercial paper program to finance the Corridor pipeline is supported by a syndicated bank credit facility that is committed during the construction period and for three years following completion of construction. The indebtedness under this credit facility and the commercial paper program are guaranteed by the Company.

The Utility's Series B Purchase Money Mortgages, Series F and Series H Debentures, and Series 11 and Series 13 Medium Term Note Debentures, and Trans Mountain's Series B and Series C Debentures are redeemable in whole or in part at the option of the Company at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond.

Required principal repayments over the next five years are as follows:

2001	\$ 72.5
2002	222.4
2003	102.5
2004	32.5
2005	247.5

4. NON-CONTROLLING INTEREST

3,000,000 6.32% cumulative redeemable first preference shares of the Utility with a face value of \$75.0 million were redeemed by the Utility on October 31, 2000 at \$25 per share. Dividends paid on these shares during the year totalled \$4.0 million (1999 – \$4.7 million).

5. CAPITAL SECURITIES AND COMMON SHARES

Authorized Share Capital

The Company is authorized to issue 750,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value.

Capital Securities

On April 19, 2000, the Company issued \$125.0 million of 8.0% Capital Securities with a term to maturity of 40 years for gross proceeds of \$123.7 million. The Company may elect to defer payments on these securities and settle such deferred payments in either cash or common shares, and has the option to settle principal at maturity through the issuance of common shares. Accordingly, the capital securities have been classified as equity. The securities are exchangeable at the option of the holder on or after April 19, 2010 for common shares of the Company at 90% of the market price, subject to the right of the Company to redeem the securities for cash. Distributions on these securities, net of related income taxes, are deducted from net earnings for the purposes of calculating earnings applicable to common shares.

Notes to Consolidated Financial Statements

Common Shares

Changes in the issued and outstanding common shares are as follows:

	2000		1999	
	Number	Amount	Number	Amount
Outstanding, beginning of year	42,871,705	\$ 363.3	42,857,873	\$ 363.0
Issued under:				
Share option plan	43,803	0.6	5,080	0.1
Payroll deduction employee share purchase plan	3,368	0.1	8,752	0.2
	42,918,876	\$ 364.0	42,871,705	\$ 363.3
Less common shares held by Trans Mountain	4,592,094		4,592,094	
Outstanding, end of year	38,326,782		38,279,611	

Reserved for issue

At December 31, 2000, the number of common shares reserved for issue to meet rights outstanding is as follows:

Under share option plan	3,692,650
Under dividend reinvestment and share purchase plan	2,062,576
Under payroll deduction employee share purchase plan	414,512
	6,169,738

6. SHARE OPTION PLAN

The Company has a Share Option Plan whereby officers, directors and certain employees may be granted options to purchase a maximum of 6,300,000 unissued common shares with terms up to ten years. The option exercise price is the closing sale price of the common shares on the Toronto Stock Exchange on the trading day prior to the date the option is granted. The Plan provides an optionee with the right, by notice in writing, to request the Company to purchase from the optionee for cash all or part of the vested options as specified in the notice at a price equal to the difference between the market price on the day the notice is received by the Company and the exercise price for those options. Upon receipt of notice requesting the Company to purchase the options from the optionee, the Company has the right to override the request and require the optionee to determine whether or not to exercise the option for unissued common shares. Options purchased by the Company are cancelled.

There are two categories of options which have been issued under the Share Option Plan, Regular Share Options and Performance Based Share Options.

Regular Share Options

The Company has granted options with ten year terms which are exercisable on a cumulative basis at 20% per annum. In 2000 the Company granted options with eight year terms which are exercisable on a cumulative basis and vest at one-third per annum on the anniversary of the option grant date.

During 2000, options to purchase 215,330 (1999 – 71,770) common shares were purchased for \$1.7 million (1999 – \$0.6 million), net of income tax benefits of \$1.5 million (1999 – \$0.4 million), which has been charged to retained earnings.

Notes to Consolidated Financial Statements

Changes in outstanding regular share options during 2000 and 1999 and outstanding options for common shares at December 31, 2000 and 1999 are as follows:

	2000		1999	
	Shares	Weighted-average exercise price	Shares	Weighted-average exercise price
Outstanding, beginning of year	971,045	\$ 18.67	1,041,145	\$ 18.31
Granted during the year	244,250	25.37	6,750	29.29
Exercised	(43,803)	14.95	(5,080)	14.12
Forfeited and expired	(17,987)	19.69	—	—
Repurchased	(215,330)	15.11	(71,770)	14.43
Outstanding, end of year	938,175	\$ 21.40	971,045	\$ 18.67
Exercisable, end of year	617,475		786,925	

Options outstanding			Options exercisable		
Exercise price range	Number of common shares	Weighted-average exercise price	Weighted-average remaining contractual life	Number exercisable at year-end	Weighted-average exercise price
\$13.87 – \$18.00	406,375	\$ 14.57	3.5	406,375	\$ 14.57
\$21.20 – \$26.65	361,500	25.61	6.9	138,800	24.93
\$27.50 – \$31.85	170,300	28.78	7.3	72,300	28.95
	938,175	\$ 21.40	5.5	617,475	\$ 18.59

Performance Based Share Options

The Company has issued performance based share options with eight year terms. The options vest at one-third per annum on the anniversary of the option grant dates, subject to the market price of the Company's common shares reaching 125% of the option's exercise price for at least 10 out of 15 consecutive trading days within four years of the option grant date. If the market price requirement is not attained in the first four years, the optionee is still eligible to exercise two-thirds of the granted options if the common share price reaches 125% of the option's exercise price for at least 10 out of 15 consecutive trading days during the subsequent four years.

Changes in outstanding performance based share options during 2000 and 1999 and outstanding options for common shares at December 31, 2000 and 1999 are as follows:

	2000		1999	
	Shares	Weighted-average exercise price	Shares	Weighted-average exercise price
Outstanding, beginning of year	295,650	\$ 26.94	—	\$ —
Granted during the year	207,327	23.17	295,650	26.94
Forfeited and expired	(11,400)	25.00	—	—
Outstanding, end of year	491,577	\$ 25.39	295,650	\$ 26.94

None of the options were exercisable at December 31, 2000. The weighted-average remaining contractual life of the options is 6.7 years.

Notes to Consolidated Financial Statements

7. EMPLOYEE BENEFIT PLANS

The Company has defined benefit plans and a defined contribution plan for employees. The Company also provides post employment benefits other than pensions including supplemental health, dental and life insurance coverage for retired employees. Information about the defined benefit plans and post employment benefits other than pensions are as follows:

	2000	1999	2000
	Pension benefit plans	Pension benefit plans	Other benefit plans
Plan assets			
Fair value at beginning of year	\$ 204.4	\$ 183.1	\$ —
Return on plan assets	18.9	21.2	—
Company contributions	3.5	5.0	—
Members' contributions	2.9	3.2	—
Benefits and settlements paid	(14.7)	(8.1)	—
Change in accounting method	10.3	—	—
Fair value at end of year	225.3	204.4	—
Accrued benefit obligation			
Balance at beginning of year	187.8	174.2	26.7
Current service cost	5.9	7.1	0.9
Interest cost	12.5	11.3	2.0
Members' contributions	2.9	3.2	—
Benefits and settlements paid	(13.6)	(8.1)	(0.7)
Change in accounting method	(7.2)	—	—
Other	1.7	0.1	2.0
Balance at end of year	190.0	187.8	30.9
Plan surplus (deficiency)	35.3	16.6	(30.9)
Unamortized transitional obligation (benefit)	(40.7)	(5.2)	22.4
Unamortized actuarial (gain) loss	(0.7)	(3.3)	2.4
Unamortized past service costs	0.9	0.4	—
Accrued benefit (liability) asset	\$ (5.2)	\$ 8.5	\$ (6.1)

Included in the above pension benefit plans is a liability of \$15.9 million at December 31, 2000 (1999 – \$14.5 million) regarding defined benefit plans which have not been funded. These unfunded pension obligations are secured by a letter of credit.

Significant Assumptions

The significant actuarial assumptions adopted in measuring the Company's accrued benefit obligations are as follows (weighted-average assumptions as of December 31):

	2000	1999	2000
	Pension benefit plans	Pension benefit plans	Other benefit plans
Discount rate	7.07%	6.99%	7.00%
Expected rate of return on plan assets	7.16%	6.86%	—
Rate of compensation increase	3.31%	3.37%	—

For measurement purposes, an 11% health care cost trend rate was assumed for 2000, decreasing gradually to 5% in 2006 and remaining at that level thereafter.

Notes to Consolidated Financial Statements

Net Benefit Plan Expense

	2000	1999	2000
	Pension benefit plans	Pension benefit plans	Other benefit plans
Current service cost	\$ 5.9	\$ 7.1	\$ 0.9
Interest cost	12.5	11.3	2.0
Expected return on plan assets	(14.7)	(12.2)	—
Amortization of transitional obligation (benefit) and other changes	(3.4)	(0.4)	2.8
Other	(0.3)	—	(0.5)
Net benefit plan expense	\$ —	\$ 5.8	\$ 5.2

The Company's defined contribution plan was introduced on January 1, 2000 and the expense for the year was \$1.0 million.

8. FINANCING COSTS

	2000	1999
Interest and expense on long-term debt	\$ 104.3	\$ 96.2
Other interest	19.5	22.4
Interest capitalized	(6.3)	(1.0)
	117.5	117.6
Dividends on 7.1% preference shares of the Utility	—	4.0
	\$ 117.5	\$ 121.6

9. RESTRUCTURING COSTS

The Company has recorded a charge of \$13.5 million (\$7.5 million after income tax) for costs relating to restructuring and relocation programs of petroleum transportation operations which will be implemented in 2001.

10. INCOME TAXES

Income Taxes on Earnings

	2000	1999
Current	\$ 54.9	\$ 50.4
Future	(17.0)	9.9
Reduction of income taxes due to utilization of prior years' losses	—	(4.9)
	\$ 37.9	\$ 55.4

Variation in Effective Income Tax Rate

Consolidated income taxes on earnings vary from the amount that would be computed by applying the Canadian and United States federal, British Columbia and Alberta combined statutory income tax rate of 44.21% (1999 – 44.70%) to earnings before income taxes and non-controlling interest as shown in the following table:

	2000	1999
Earnings before income taxes and non-controlling interest	\$ 125.6	\$ 134.3
Combined statutory income taxes	\$ 55.5	\$ 60.0
Add (deduct) tax effect of:		
Capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	(8.2)	(6.3)
Large Corporations Tax	4.8	5.0
Reduction in corporate tax rates and capital gains inclusion rate in future years	(8.5)	—
Utilization of prior years' losses	—	(4.9)
Non-taxable income and non-deductible expenses	(3.7)	1.8
Other	(2.0)	(0.2)
Actual consolidated income taxes on earnings	\$ 37.9	\$ 55.4

Notes to Consolidated Financial Statements

Future Income Taxes

The net future income tax liability of the Company of \$47.3 million relates primarily to the tax effect of temporary differences on non-regulated property, plant and equipment balances.

As a result of the Company accounting for income taxes following the taxes payable method for its regulated operations, the Company has not recognized net future income tax liabilities amounting to \$222.8 million at December 31, 2000 (1999 – \$279.1 million) and has not recognized a future income tax recovery of \$56.3 million for the year ended December 31, 2000, all of which were calculated under the asset and liability method.

11. NW ENERGY MONETIZATION

On October 19, 1999 the Company sold its interest in the cash flow of NW Energy, which owns a wood waste-fired independent electricity generating power plant, to TransCanada Power, L.P. The Company received net proceeds of \$25.6 million which, along with income tax benefits that were recognized in 1999 and 2000, resulted in a gain of \$7.0 million in 1999 and \$29.0 million in 2000. As at December 31, 2000, the Company no longer owns any interest in NW Energy.

12. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The carrying value of cash, accounts receivable, short-term notes and accounts payable and accrued liabilities approximates their fair value due to the relatively short period to maturity of the instruments.

The fair value of the Company's long-term debt, calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 2000, or by using available quoted market prices, is estimated at \$1,790.0 million (1999 – \$1,204.4 million). All of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment.

Derivative Instruments

The Company uses derivative instruments to hedge its exposures to fluctuations in energy prices, interest rates and foreign currency exchange rates. These instruments are for terms of less than one year.

Natural gas derivatives are used to manage natural gas price risk in the natural gas distribution operations. The majority of the natural gas supply contracts of the natural gas distribution operations have floating prices for natural gas, rather than fixed prices. On behalf of customers, the Company uses natural gas price swap contracts to fix the effective purchase price. Any differences between the effective cost of natural gas purchased and the price of natural gas used for rate making purposes are managed through the regulatory process whereby differences are recorded in a deferral account and passed through to customers in future rates.

Within the natural gas distribution operations, interest rate and foreign currency risk is managed mainly through the regulatory process. As at December 31, 2000, \$99 million (1999 – \$198 million) of short-term borrowings in the natural gas distribution operations were subject to interest rate deferral accounts. Foreign currency risk in the natural gas distribution operations relates mainly to purchases and sales of natural gas denominated in U.S. dollars, and is thereby managed through the regulatory process.

Short-term borrowings in the petroleum transportation and other activities segments are exposed to interest rate risk. The only material foreign currency risk in those business segments relates to the U.S. portion of Trans Mountain's crude oil pipeline system. The petroleum transportation and other activities segments manage interest rate and foreign currency exposures through the use of interest rate and foreign currency derivatives.

The carrying values of natural gas derivatives at December 31, 2000 were \$20.4 million (1999 – liability of \$0.7 million) and the fair values of the derivatives were \$113.2 million (1999 – liability of \$2.7 million). The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates. There were no significant foreign currency or interest rate derivatives outstanding at the end of 2000 or 1999.

The Company is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. Because it deals with high credit quality institutions in accordance with its established credit approval practices, the Company does not expect any counterparties to fail to meet their obligations.

Notes to Consolidated Financial Statements

13. SEGMENT DISCLOSURES

The Company operates principally in two business segments:

(a) Natural gas distribution, primarily involving the transmission and distribution of natural gas for residential, commercial and large industrial customers in British Columbia; and

(b) Petroleum transportation, primarily involving the transportation of crude and refined petroleum products principally for seven major shippers from Alberta to the west coast of British Columbia and Washington state and the Corridor pipeline.

The Company has other activities which include non-regulated energy and utility services as well as corporate interest and administration charges. The non-regulated services include international consulting, multi-utility supply and services, retail energy services and, to October 19, 1999, independent power production of NW Energy. The Company also operates in the United States. At the present time, these operations are not of sufficient size to be reportable as operating or geographic segments.

2000				
	Natural gas distribution	Petroleum transportation	Other activities	Total
Revenues	\$ 1,085.4	\$ 132.5	\$ 87.7	\$ 1,305.6
Depreciation and amortization	67.1	17.7	1.4	86.2
Operating income	201.8	49.7	5.1	256.6
Financing costs	96.7	15.0	5.8	117.5
Restructuring costs	—	13.5	—	13.5
Income taxes (recovery) on earnings	42.4	(1.1)	(3.4)	37.9
Income tax benefits from NW Energy	—	—	(29.0)	(29.0)
Net earnings	58.7	22.3	31.7	112.7
Net earnings applicable to common shares	58.7	22.3	27.8	108.8
Earnings per common share	1.53	0.58	0.73	2.84
Total assets	2,911.9	536.4	64.8	3,513.1
Capital expenditures	472.5	140.6	7.5	620.6

1999				
	Natural gas distribution	Petroleum transportation	Other activities	Total
Revenues	\$ 844.7	\$ 129.4	\$ 66.5	\$ 1,040.6
Depreciation and amortization	62.5	15.4	5.2	83.1
Operating income	192.7	47.9	15.3	255.9
Financing costs	87.5	14.8	19.3	121.6
Income taxes (recovery) on earnings	48.8	13.6	(7.0)	55.4
Income tax benefits from NW Energy	—	—	(7.0)	(7.0)
Net earnings	51.7	19.5	10.0	81.2
Net earnings applicable to common shares	51.7	19.5	10.0	81.2
Earnings per common share	1.35	0.51	0.26	2.12
Total assets	2,045.6	404.0	31.3	2,480.9
Capital expenditures	133.8	24.8	5.0	163.6

14. COMMITMENTS

(a) The Utility and Trans Mountain have entered into operating leases in respect of their head office and other premises. Minimum payments under these leases are on average approximately \$10.8 million in each of the next five years and \$100.4 million in aggregate.

(b) The Company has agreed to construct the Corridor pipeline at an estimated cost of \$688 million.

Consolidated Financial Information (Five Years)

Unaudited

(Dollar amounts in millions)

Years ended December 31	2000	1999	1998	1997	1996
Statements of Earnings					
Operating revenue	\$ 1,305.6	\$ 1,040.6	\$ 925.0	\$ 933.9	\$ 901.4
Operating expenses	1,049.0	784.7	664.5	689.9	670.1
Operating income	256.6	255.9	260.5	244.0	231.3
Other expenses	131.0	121.6	121.8	137.8	89.7
Income taxes	8.9	48.4	62.9	49.6	32.1
Non-controlling interest	4.0	4.7	4.6	5.8	3.9
Net earnings	112.7	81.2	71.2	50.8	105.6
Capital securities distributions	3.9	—	—	—	—
Earnings applicable to common shares	\$ 108.8	\$ 81.2	\$ 71.2	\$ 50.8	\$ 105.6
Assets					
Current assets	\$ 631.2	\$ 270.7	\$ 224.9	\$ 188.9	\$ 305.2
Property, plant and equipment (net)	2,727.6	2,185.1	2,168.6	2,116.1	2,062.6
Other assets	154.3	25.1	72.6	83.1	59.3
Total assets	\$ 3,513.1	\$ 2,480.9	\$ 2,466.1	\$ 2,388.1	\$ 2,427.1
Liabilities and Shareholders' Equity					
Current liabilities	\$ 1,094.4	\$ 712.4	\$ 858.1	\$ 696.7	\$ 648.2
Long-term debt	1,561.9	1,001.8	906.7	993.3	1,033.9
Other liabilities	47.3	140.4	111.3	109.9	114.3
Shareholders' equity	809.5	626.3	590.0	588.2	630.7
Total liabilities and shareholders' equity	\$ 3,513.1	\$ 2,480.9	\$ 2,466.1	\$ 2,388.1	\$ 2,427.1
Cash Flow Data					
Operating cash flow	\$ 179.3	\$ 124.1	\$ 80.2	\$ 170.6	\$ 166.8
Capital expenditures	\$ 620.6	\$ 163.6	\$ 128.7	\$ 130.0	\$ 145.7

Operating Information (Five Years)

Unaudited

(Dollar amounts in millions)

Years ended December 31	2000	1999	1998	1997	1996
Natural Gas Distribution Operations					
Revenues					
Residential	\$ 627.8	\$ 493.2	\$ 423.1	\$ 431.1	\$ 405.5
Commercial	336.3	262.2	226.3	246.9	231.3
Small industrial	52.3	26.7	22.5	17.3	14.7
Large industrial and other	7.7	8.8	19.1	19.7	19.4
Total natural gas sales revenue	\$ 1,024.1	\$ 790.9	\$ 691.0	\$ 715.0	\$ 670.9
Transportation	41.0	38.4	33.6	28.6	33.9
Other	20.3	15.4	17.8	22.2	19.5
Total natural gas revenue	\$ 1,085.4	\$ 844.7	\$ 742.4	\$ 765.8	\$ 724.3
Natural gas volumes (billion cubic feet)					
Sales volumes	124.0	121.8	117.1	123.0	129.5
Transportation volumes	56.3	57.6	52.1	52.0	53.0
Total natural gas volumes	180.3	179.4	169.2	175.0	182.5
Customers at year end	762,878	755,383	742,305	732,316	716,421
Petroleum Transportation Operations					
Revenues	\$ 132.5	\$ 129.4	\$ 135.4	\$ 129.1	\$ 132.8
Transportation volumes (m ³ /day)					
Canadian mainline	32,533	32,988	40,160	36,523	39,681
Jet fuel deliveries	3,149	3,196	3,260	3,279	3,358
Total throughput	35,682	36,184	43,420	39,802	43,039
U.S. mainline (included in Canadian mainline)	10,365	9,847	16,128	15,004	16,294
Kilometres of pipelines					
Natural gas distribution	37,197	36,581	36,473	35,971	35,335
Petroleum transportation	1,477	1,477	1,477	1,477	1,477
Employees (consolidated)	1,966	1,869	1,819	1,979	1,965

Consolidated Financial Information (Five Years)

Unaudited

Years ended December 31	2000	1999	1998	1997	1996
Ratios					
Return on average common equity	12.0%	12.2%	12.1%	10.7%	10.3%
Dividend payout ratio	0.43	0.55	0.59	0.77	0.36
Interest coverage ratio	2.18	2.10	2.14	2.13	1.83
Debt/debt plus shareholders' equity	0.71	0.71	0.73	0.71	0.69
Common shares outstanding					
– weighted average	38.3	38.3	38.5	40.1	41.8
Data Per Common Share					
Earnings before non-recurring items	\$ 2.06	\$ 1.94	\$ 1.85	\$ 1.63	\$ 1.48
Earnings after non-recurring items	\$ 2.84	\$ 2.12	\$ 1.85	\$ 1.27	\$ 2.53
Dividends	\$ 1.225	\$ 1.165	\$ 1.090	\$ 0.975	\$ 0.900
Operating cash flow	\$ 4.68	\$ 3.24	\$ 2.08	\$ 4.25	\$ 3.99
Common equity	\$ 17.86	\$ 16.36	\$ 15.42	\$ 15.05	\$ 15.28
Market price range – High	\$ 33.50	\$ 31.40	\$ 34.00	\$ 28.00	\$ 21.15
– Low	\$ 21.50	\$ 20.45	\$ 25.50	\$ 20.10	\$ 15.00
– Close	\$ 33.35	\$ 25.40	\$ 30.50	\$ 27.80	\$ 20.30

Quarterly Financial Information

Unaudited

In millions, except where stated otherwise

	Three months ended				Year ended
2000	March	June	September	December	December
Revenues	\$ 383.9	\$ 240.2	\$ 213.9	\$ 467.6	\$ 1,305.6
Net earnings (loss)	\$ 61.3	\$ 9.6	\$ (11.3)	\$ 53.1	\$ 112.7
Earnings (loss) applicable to common shares	\$ 61.3	\$ 8.5	\$ (12.7)	\$ 51.7	\$ 108.8
Data per common share					
Earnings (loss)	\$ 1.60	\$ 0.22	\$ (0.33)	\$ 1.35	\$ 2.84
Dividends paid	\$ 0.295	\$ 0.310	\$ 0.310	\$ 0.310	\$ 1.225
Common share trading – TSE					
High	\$ 26.50	\$ 30.00	\$ 30.20	\$ 33.50	\$ 33.50
Low	\$ 21.50	\$ 24.55	\$ 26.40	\$ 27.25	\$ 21.50
Close	\$ 25.00	\$ 28.30	\$ 28.35	\$ 33.35	\$ 33.35
Volume	4.7	2.3	1.9	2.2	11.1
Common shares outstanding					
– weighted average	38.3	38.3	38.3	38.3	38.3

1999

Revenues	\$ 342.1	\$ 209.3	\$ 164.3	\$ 324.9	\$ 1,040.6
Net earnings (loss)	\$ 51.6	\$ (0.4)	\$ (12.8)	\$ 42.8	\$ 81.2
Earnings (loss) applicable to common shares	\$ 51.6	\$ (0.4)	\$ (12.8)	\$ 42.8	\$ 81.2
Data per common share					
Earnings (loss)	\$ 1.35	\$ (0.01)	\$ (0.34)	\$ 1.12	\$ 2.12
Dividends paid	\$ 0.280	\$ 0.295	\$ 0.295	\$ 0.295	\$ 1.165
Common share trading – TSE					
High	\$ 31.40	\$ 30.85	\$ 30.70	\$ 27.25	\$ 31.40
Low	\$ 26.75	\$ 27.10	\$ 25.30	\$ 20.45	\$ 20.45
Close	\$ 27.25	\$ 30.10	\$ 27.25	\$ 25.40	\$ 25.40
Volume	3.6	2.8	1.5	3.5	11.4
Common shares outstanding					
– weighted average	38.3	38.3	38.3	38.3	38.3

GLOSSARY

BITUMEN

A hydrocarbon liquid of high density and viscosity. In Alberta, it is usually associated with oil sands deposits and when extracted it is too viscous to be transported by pipeline at normal ambient conditions.

BRITISH COLUMBIA UTILITIES COMMISSION

A provincially appointed body that regulates the potential earnings, business operations and practices of several B.C. utilities.

BTU

British thermal unit. The amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.

CORE MARKET

Generally refers to non-industrial and non-utility purchasers of natural gas and includes residential, commercial and institutional (i.e., hospitals, universities) purchasers of natural gas.

DEMAND CHARGE

The portion of the cost of transportation that is payable on the full contracted capacity regardless of whether or not the space is used.

DEMAND SIDE MANAGEMENT (DSM)

Utility programs designed to influence the customer's energy consumption. Such programs include reducing gas consumption through efficiency and conservation, load shaping programs to reduce peak load and/or increase off peak load, and programs to encourage fuel substitution.

DILUENT

A hydrocarbon liquid of low density and viscosity. It is usually blended with raw bitumen to create a fluid which can be transported by pipeline at normal ambient conditions.

FIXED PRICE CONTRACTS

Contractual requirements for the purchase of a minimum quantity of gas whether or not delivery is accepted by the purchaser.

GIGAJOULE (GJ)

0.95 thousand cubic feet of natural gas at 1000 Btu per cubic foot or 0.28 megawatt hours of electricity. Terajoule (TJ) is one thousand gigajoules and petajoule (PJ) is one million gigajoules.

INTERRUPTIBLE CUSTOMERS

Gas customers who choose low priority service, usually at lower rates under schedules or contracts that anticipate and permit interruption of gas service on short notice, generally in peak load seasons.

INTERVENOR

An active participant in a hearing, typically representing one or a group of customers.

MULTI-UTILITY

In the future, one service provider will deliver multiple utilities, including natural gas, water and electricity. Advances in technology will also allow for metering of different commodities through one meter.

NATIONAL ENERGY BOARD

A federal regulatory body that oversees interprovincial and international oil and gas pipelines, as well as the export and import of electricity, oil and gas.

PEAK SHAVING

The process of supplying gas to a utility system from an auxiliary source, such as storage or liquefied natural gas, during periods of maximum demand to reduce the load or demand on the primary source of supply, usually a pipeline.

RATE BASE

The investment in gas plant in service and working capital on which utilities earn a rate of return to compensate shareholders and holders of the utility debt.

REVENUE REQUIREMENT

The total revenues to be generated by rates in order to recover the costs of providing service.

SHIPPERS

Entities holding transportation contracts on pipelines which require payment of tolls.

TCF

Trillion (10¹²) cubic feet of natural gas.

TOLLS

The rates charged by pipeline companies under tariffs approved by regulatory bodies for such services as raw gas transmission, processing and transportation.

TRANSPORTATION

A gas delivery service provided by a pipeline or local gas utility company to customers who purchase natural gas directly from producers or brokerage companies.

METRIC TO IMPERIAL CONVERSIONS

1 GJ =	0.9482 MMBtu
1 10 ³ m ³ =	35.301 MCF
1 m ³ =	6.290 Barrels
1 km =	0.6214 miles

BOARD OF DIRECTORS

L. I. (Larry) Bell
West Vancouver, British Columbia
Vice Chair, Shato Holdings Ltd.

Robert G. Brodie
Barbados
Chairman, Cardiff Properties Ltd.

Thomas A. Buell
Delta, British Columbia
Corporate Director

Brian A. Canfield
Point Roberts, Washington, U.S.A.
Chairman, TELUS

Donald A. Carlson
Edmonton, Alberta
President, Carlson Development Corporation Ltd.

Marilyn E. Cassady
Vancouver, British Columbia
Corporate Director

Ronald L. Cliff, C.M., FCA
West Vancouver, British Columbia
Chairman of the Board, BC Gas Inc.

Mark L. Cullen
Vancouver, British Columbia
President, Mark Cullen & Company Ltd.

David L. Emerson
Vancouver, British Columbia
President and Chief Executive Officer, Canfor Corporation

Iain J. Harris
Vancouver, British Columbia
Vice Chairman, BC Gas Inc.
Chairman and Chief Executive Officer, Summit Holdings Ltd.

Robert E. Kadlec
West Vancouver, British Columbia
Chairman and Chief Executive Officer, Bentley Capital Corp.

John M. Reid
Vancouver, British Columbia
President and Chief Executive Officer, BC Gas Inc.

Robert T. Stewart
West Vancouver, British Columbia
President, R. T. Stewart & Associates

David W. Strangway
Vancouver, British Columbia
President, Canada Foundation for Innovation

Douglas W. G. Whitehead
Coquitlam, British Columbia
President and Chief Executive Officer, Finning International Inc.

BC Gas Inc. directors are also directors of BC Gas Utility Ltd. and Trans Mountain Pipe Line Company Ltd.

COMMITTEES OF THE BOARD

Executive Committee

R. L. Cliff (Chair),
 I. J. Harris, J. M. Reid and R. T. Stewart

Exercises all the powers of the Directors (except for certain significant decisions reserved by the Board of Directors) in overseeing the management and direction of the Company during intervals between Board meetings.

Audit Committee

I. J. Harris (Chair),
 B. A. Canfield, M. L. Cullen,
 D. L. Emerson and R. T. Stewart

Acts on behalf of the Board in reviewing certain financial information prepared for public distribution and in monitoring internal accounting controls. The Committee is responsible for assuring that the Company's financial statements accurately portray the financial condition of the Company and for providing reasonable assurances that the Company is in compliance with applicable laws and regulations, is conducting its affairs ethically and maintains effective controls. The Committee also recommends the appointment, change or reappointment of auditors.

Management Resources Committee

L. I. Bell (Chair)
 B. A. Canfield, R. E. Kadlec,
 D. W. Strangway and D. W. G. Whitehead

Ensures the Company has a plan for continuity of its officers and an executive compensation plan that is motivational and competitive in order to attract, hold and inspire the performance of Executive Management and other key personnel. The intent of the Committee is to enhance the profitability and growth of the Company through effective succession planning.

Corporate Governance Committee

T. A. Buell (Chair)
 R. G. Brodie, D.A. Carlson, M. L. Cullen
 and D. W. Strangway

Ensures that an effective and efficient approach to corporate governance is developed and implemented, with the objective of assuring the business and affairs of the Company are carried out in a manner that will enhance shareholder value. In consultation with the Chairman of the Board, the Committee is responsible for identifying, evaluating and recommending nominees for the Board of Directors.

Environment and Safety Committee

M. E. Cassady (Chair),
 L. I. Bell, R. G. Brodie, I. J. Harris and
 D. W. G. Whitehead

Reviews and approves corporate environmental policy, evaluates the Company's progress in implementing the policy, reviews relevant data and reports, and brings information and recommendations to the attention of the Board as appropriate.

OFFICERS

BC GAS INC.

Ronald L. Cliff, C.M., FCA
Chairman of the Board

Iain J. Harris
Vice Chairman

John M. Reid
President and Chief Executive Officer

Gordon R. Barefoot
Senior Vice President, Planning & Development

Michael A. Sharp
Senior Vice President, Residential Customers

Milton C. Woensdregt
Senior Vice President, Finance, Chief Financial Officer, and Treasurer

Donald C. Fairbairn
Vice President, Business Development

David M. Masuhara
Vice President and Secretary

Debra G. Nelson
Assistant Corporate Secretary

BC GAS UTILITY LTD.

Ronald L. Cliff, C.M., FCA
Chairman of the Board

Iain J. Harris
Vice Chairman

John M. Reid
President and Chief Executive Officer

Randall L. Jespersen
Senior Vice President, Energy Delivery Services

Patrick D. Lloyd
Senior Vice President, Business Technologies & Support

Michael A. Sharp
Senior Vice President, Residential Customers

Milton C. Woensdregt
Senior Vice President, Finance, Chief Financial Officer, and Treasurer

Mary E. Bruce
Vice President, Human Resources

Ronald J. Jupp
Vice President, Distribution Operations

Jan A. Marston
Vice President, Gas Supply & Transportation

David M. Masuhara
Vice President, Legal, Regulatory & Logistics, and Secretary

Duncan S. Vickers
Vice President, Information & Communications Technology

Debra G. Nelson
Assistant Corporate Secretary

TRANS MOUNTAIN PIPE LINE COMPANY LTD.

Ronald L. Cliff, C.M., FCA
Chairman

John M. Reid
Vice Chairman

Thomas D. Doyle
President

John L. Fingarson
Vice President, Secretary and General Counsel

Michael R. Horner
Vice President, Corridor Pipeline Project

Robert D. Vergette
Vice President, Operations

Liisa A. O'Hara
Vice President, Financial Services & Regulatory Affairs

Milton C. Woensdregt
Treasurer

Michael W. P. Boyle
Corporate Solicitor and Assistant Secretary

Cheryl L. Berge
Controller and Assistant Treasurer

INVESTOR INFORMATION

ANNUAL GENERAL MEETING

The Annual General Meeting of Shareholders will be held at 11:00 a.m. on Thursday, April 26, 2001 in the Park Ballroom of the Four Seasons Hotel in Vancouver, British Columbia.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Registered holders of the Company's Common shares (except residents of the United States) may elect to reinvest their cash dividends in new Common shares. Participants in the Plan may also make optional cash payments of up to \$20,000 per calendar year to purchase additional Common shares. Optional cash payments must be received by the Registrar and Transfer Agent by the last days of January, April, July and October to be reinvested on the following dividend payment date. There are no brokerage commissions payable on shares purchased pursuant to the Plan. For an information package on the Plan, or to register in the Plan, please contact Shareholder Relations.

EMPLOYEE SHARE PURCHASE PLAN

Employees of BC Gas Utility Ltd. may contribute from 2% to 6% of their earnings through payroll deductions to purchase the Company's Common shares. Shares are purchased at 100% of the market price.

COMMON SHARE DISTRIBUTION

Approximately 99.2% of the outstanding Common shares are owned by residents of Canada. The following table summarizes the distribution of shares at December 31, 2000.

	Shareholders	Shares
Canada	6,949	42,584,299
USA	106	291,910
Others	29	42,667
Total	7,084	42,918,876

COMMON SHARE OWNERSHIP CONSTRAINTS

In accordance with the statute that privatized the Company, the following constraints on BC Gas Inc. share ownership exist: (i) the total number of voting shares held by any one person or associated persons shall not exceed 10% of the total number of issued and outstanding voting shares; and (ii) non-Canadian citizens and non-residents of Canada will not be permitted to hold or beneficially own in the aggregate, directly or indirectly, more than 20% of the total number of the issued and outstanding voting shares of the Company.

Valuation Day Value (December 22, 1971)
Common Shares¹ \$6.50
February 22, 1994 Closing Price, \$15.50

¹Adjusted for the two-for-one stock split on November 18, 1985.

REGISTRAR AND TRANSFER AGENT

Shareholder accounts, including dividend payments, direct deposit service and the transfer of shares are handled by the Company's registrar and transfer agent:

CIBC Mellon Trust Company
16th Floor, 1066 West Hastings Street
Vancouver, B.C. V6E 3X1
Telephone: (604) 688-4330
Toll Free: 1-800-387-0825
Fax: (604) 688-4301
Web site: www.cibcmellon.com

DUPLICATE ANNUAL AND INTERIM REPORTS

To eliminate duplicate mailings of annual and quarterly reports, please contact CIBC Mellon Trust Company.

SHARES LISTED (SYMBOL: BCG)

The Toronto Stock Exchange

SCHEDULED DIVIDEND PAYMENT DATES

February 28, 2001
May 31, 2001
August 31, 2001
November 30, 2001



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Project management: Alette Communication Inc.

CORPORATE OFFICES

BC Gas Inc. and
BC Gas Utility Ltd.
1111 West Georgia Street
Vancouver, B.C. V6E 4M4
Telephone: (604) 576-7000
Toll Free: 1-800-773-7001

Trans Mountain Pipe Line Company Ltd.
Suite 900 - 1333 West Broadway
Vancouver, B.C. V6H 4C2
Telephone: (604) 739-5000

SHAREHOLDER RELATIONS

Inquiries regarding the Company's
Dividend Reinvestment and Share
Purchase Plan and all other inquiries or
comments by shareholders regarding
the Company should be directed to:

Debra Nelson
Assistant Corporate Secretary
Telephone: (604) 443-6559
Toll Free (Canada): 1-800-667-9177
Fax: (604) 443-6904
E-mail: shareholder@bcgas.com

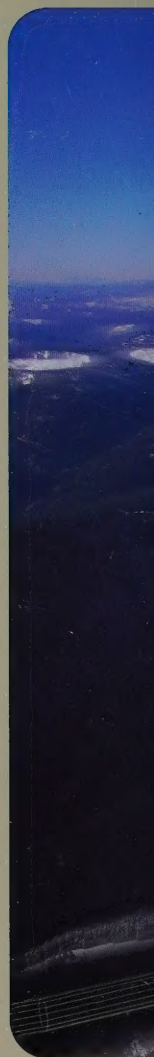
INVESTOR RELATIONS

Portfolio managers, investment
analysts and other investors
requesting financial information
regarding BC Gas should contact:

David Bryson
Assistant Treasurer
Telephone: (604) 443-6527
Fax: (604) 443-6929
E-mail: ir@bcgas.com

INTERNET

Web site: www.bcgas.com



CONTACT US AT
SHAREHOLDER RELATIONS
TOLL-FREE: 1-800-667-9177
E-MAIL: shareholder@bcgas.com



INVESTOR RELATIONS
E-MAIL: ir@bcgas.com
OR VISIT OUR WEB SITE AT:
www.bcgas.com